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Susan Frank
Vice President and Chief Regulatory Officer
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BY COURIER

July 31, 2014

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2014-0244 – MAAD S86 Hydro One Networks Inc. Application to Purchase Haldimand County Utilities Inc.

I am attaching two (2) paper copies of Hydro One Inc's MAAD Application for the acquisition of Haldimand County Utilities Inc. Please note that information has been redacted in Exhibit A, Tab 3, Schedule 1, Attachment 6 pertaining to employee, property owner, and account information.

An electronic copy of the complete application has been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

attach.

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15 (the "**Act**").

IN THE MATTER OF an application made by Hydro One Inc. for leave for Hydro One Inc., acting through its subsidiary 1908872 Inc.. (referred to collectively hereinafter as "**Hydro One Inc.**") to purchase all of the issued and outstanding shares of Haldimand County Utilities Inc., made pursuant to section 86(2)(b) of the Act.

AND IN THE MATTER OF an application made by Haldimand County Hydro Inc. to include a rate rider in the 2014 Ontario Energy Board (**"OEB"**) approved rate schedule of Haldimand County Hydro Inc. to give effect to a 1% rate reduction relative to 2014 base electricity delivery rates (exclusive of rate riders), made pursuant to section 78 of the Act.

AND IN THE MATTER OF an application made by Haldimand County Hydro Inc. for leave to transfer its distribution system to Hydro One Networks Inc., made pursuant to section 86(1)(a) of the Act.

AND IN THE MATTER OF an application made by Haldimand County Hydro Inc. for leave to transfer Haldimand County Hydro Inc.'s distribution licence and rate order to Hydro One Networks Inc., made pursuant to section 18 of the Act.

APPLICATION

1.0 INTRODUCTION

Hydro One Inc. (**"HOI"**) is an Ontario corporation with its head office in the City of Toronto. HOI is wholly-owned by the Province of Ontario and is the parent company of Hydro One Networks Inc. (**"Hydro One"**), 1908872 Ontario Inc., Hydro One Brampton Networks Inc., Hydro One Remote Communities Inc., Norfolk Power Distribution Inc. and Hydro One Telecom Inc.

Hydro One's distribution system serves approximately 1.2 million customers in its service territory (see **Exhibit A, Tab 3, Schedule 1, Section 1.3.3** for further customer details).

Haldimand County Hydro Inc. (**"HCHI"**) is a wholly-owned subsidiary, at the date of this application, of Haldimand County Utilities Inc. (**"HCUI"**). HCUI is a holding company, currently wholly-owned by The Corporation of Haldimand County (**"Haldimand County"**).

HCHI's distribution system serves approximately 21,264 Residential and General Service customers in the HCHI service territory (see **Exhibit A, Tab 3, Schedule 1, Section 1.3.3** for further customer details).

2.0 OVERVIEW OF APPLICATION

On June 10, 2014, Haldimand County (the **"Vendor"**) and HOI, through its wholly-owned affiliate 1908872 Ontario Inc. (the **"Purchaser"**)[1], entered into a share purchase agreement (the

[1] The Share Purchase Agreement is structured between The Corporation of Haldimand County, 1908872 Ontario Inc. and Hydro One Inc. 1908872 Ontario Inc. was used to allow for tax efficient integration of the two corporate structures. The shares held by 1908872 Ontario Inc. will be transferred to HOI after closing. As such, this OEB application has referenced the transaction as between HOI and The Corporation of Haldimand County

"Agreement"), under which the Vendor has agreed to sell, and the Purchaser has agreed to purchase, all of the issued and outstanding shares of HCUI (the **"Purchased Shares"**). The purchase price is $75.0 million, comprised of a cash payment of approximately $65.2 million for the Purchased Shares and the assumption of HCUI's short and long-term debt of approximately $9.8 million. The Agreement contemplates the transaction closing after all conditions precedent are met and within the 90 days following the Parties' receipt of all required approvals, including Ontario Energy Board (**"the Board"** or **"OEB"**) approval of this Application under sections 86(2) and 86(1) of the Act.

The Agreement (see **Exhibit A, Tab 3, Schedule 1, Attachment 6**) includes the following customer-focused actions in addition to the sale of the shares:

(a) HCHI will apply to the OEB for approval to include a negative rate rider to HCHI's electricity rates (effective May 1, 2014) to reduce base delivery distribution rates by one per cent across all Rate Classes, and to have such reduced rates apply for the next five years (see **Exhibit A, Tab 2, Schedule 1, Section 1.2** for further detail);

(b) During the period in which the negative rate rider is in effect, Hydro One and HCHI intend to transfer HCHI's regulated distribution system assets so that they are owned by, integrated with, and form part of Hydro One's existing distribution system. The Parties therefore seek to have HCHI's existing Electricity Distribution Licence (ED-2002-0539) and Rate Orders transferred to Hydro One. Asset transfer and integration steps are expected to occur within 18 months after the close of the transaction;

(c) Following the effective period for the negative rate rider, Hydro One expects to apply to harmonize HCHI rates with Hydro One's revenue requirement. The rebasing and rate harmonization application is expected to take effect in 2020 and will be based on then-prevailing forecast costs as discussed in **Exhibit A, Tab 2, Schedule 1, Section 2**;

(d) The Purchaser or its affiliates shall offer all active employees of HCHI continued employment in Haldimand County for a period of at least one year;

(e) The Purchaser and the Vendor shall establish an advisory committee (the **"Advisory Committee"**) to provide a forum for communication between the Purchaser and the Vendor. In establishing the Advisory Committee, the Purchaser shall select representatives, including the local superintendent from Hydro One's Zone 2 or equivalent, in consultation with officials of the Vendor. The Vendor has the right to appoint at least three representatives to the Advisory Committee; and

(f) If at any time during the period beginning on the closing date and continuing for the five years following closing date, the five-year rolling average for reliability in HCHI's pre-closing territory falls below the average reliability reported by HCHI to the OEB for the five years prior to closing, the Purchaser shall make a payment to the Vendor in the amount of $100,000, to be used to address charitable or other community interests.

The purchase price is subject to adjustment, within 90 days following closing, for working capital, net fixed assets and long term debt, in accordance with the Agreement.

3.0 OEB APPROVAL REQUESTS

- HOI is applying to the Board pursuant to section 86(2)(b) of the Act, for leave to acquire all the issued and outstanding shares of HCUI from the Vendor.
- HCHI is applying pursuant to section 86(1)(a) of the Act, for leave to transfer its distribution system to Hydro One.
- HCHI is applying pursuant to section 18 of the Act, for leave to transfer HCHI's distribution licence and rate order to Hydro One. The rate base value of HCHI's assets is approximately $52.3 million and will be transferred to Hydro One Distribution's rate base.
- HCHI is applying for approval to include a rate rider in the 2014 OEB-approved rate schedule of HCHI to give effect to reducing the approved 2014 base delivery distribution rates (EB-2013-0134) by one per cent. See **Exhibit A, Tab 2, Schedule 1, Section 1.2** for further information.

- HCHI is applying for approval to extend the rate rider Funding Adder for Renewable Energy Generation to be in effect until the effective date of the next cost of service application.
- Hydro One is applying for approval to defer the rate rebasing of the Hydro One Haldimand[2] business unit for five years from the date of closing the proposed transaction, consistent with the Report of the Board titled "Rate-making Associated with Distributor Consolidation" issued July 23, 2007. At the end of the five-year period, Hydro One expects to file a rate application at the earliest opportunity to rebase rates, currently expected in 2020. See **Exhibit A, Tab 2, Schedule 1, Section 2** for further information.
- Hydro One is applying for approval to continue to track costs to the regulatory asset accounts currently approved by the OEB for HCHI and to seek disposition of their balances at a future date. See **Exhibit A, Tab 2, Schedule 1, Section 1.2.2** for further details.
- Hydro One is applying for approval to utilize USGAAP for HCHI financial reporting.

Hydro One respectfully requests a written hearing for this Application and submits that the evidence supports approval of the Application for the following reasons:

- The approval of the Application has no adverse impact on the price, adequacy, reliability and quality of electricity service of HCHI or Hydro One. In addition, it promotes electricity conservation and demand management, the use and generation of electricity from renewable energy sources and facilitates the implementation of a smart grid in Ontario;
- The customers of both local distribution companies will be held harmless;
- The transaction eliminates the duplication of effort between Hydro One and HCHI and results in a single electric distribution service provider for all of the broader region of Norfolk and Haldimand Counties. This will ultimately lead to lower cost of service across all of Hydro One's service areas including HCHI and the recently acquired Norfolk Power Distribution Inc., which will create downward pressure on electricity distribution rates; and
- This transaction was completed on a commercial basis between a willing seller and a willing buyer. It is a demonstration of the type of benefits that can be realized from voluntary

[2] HCHI once fully integrated into Hydro One is referenced as Hydro One Haldimand.

consolidation. It will deliver cost synergies and economy of scale benefits contemplated by the Ontario Distribution Sector Review Panel and will promote the objectives contained in the OEB's Renewed Regulatory Framework for Electricity Distributors.

SUPPLEMENTARY TRANSACTION INFORMATION

This exhibit provides information addressing how the proposed transaction meets the merger, acquisition, amalgamation and divesture (**"MAAD"**) requirements set forth in the *Ontario Energy Board Act*, *1998* (the **"Act"**) and details both quantitative and qualitative savings expected as a result of this transaction. Further details on approvals sought with respect to customer rates and bill impacts, timing of rebasing, regulatory assets and riders, USGAAP and compliance matters are also discussed.

MAAD APPLICATION REQUIREMENTS

1.0 CONSUMER PROTECTION

Section 1 of the Act requires that the Ontario Energy Board ("**Board**" or "**OEB**"), in carrying out its responsibilities, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry;
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances;
4. To facilitate the implementation of a smart grid in Ontario; and
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

In the recent Hydro One/Norfolk Power Inc. MAAD Application (EB-2013-187/EB-2013-0196/EB-2013-0198), the Board found in its Decision and Order dated July 3, 2014, that the "no harm test" remains the relevant benchmark and that Section 1 of the Act remains the approved determinant to meet the Board's objectives.[1]

1.1 Economic Efficiency and Cost Effectiveness

Hydro One projects that the resultant cost structures from proceeding with the transaction will result in ongoing operations, maintenance and administrative (**"OM&A"**) savings of over $4.0 million per year and reductions in capital expenditures of over $1.5 million per year. These savings will result in downward pressure on HCHI's cost structure, which would tend to decrease rates relative to the status quo. Quantitative savings will be realized through cost synergies in the following areas, which will be discussed in more detail in the section following:

- reduction in back-office staff, including accounting, administration, and customer service;
- reprioritization of capital program costs utilizing Hydro One's Asset Risk Assessment (**"ARA"**) process;
- reduction in information technology (**"IT"**) costs, such as hardware and software maintenance fees;
- reduction in corporate governance costs, with the elimination of the HCHI Board of Directors;
- reduction in senior management costs;
- rationalization of smart grid, conservation and demand management, and renewable energy initiatives;
- reduction in future regulatory costs associated with fulfilling regulatory requirements, including the preparation and filing of regulatory applications, including IRM and COS applications; and

[1] EB-2013-0196/0187/0198 Decision and Order dated July 3, 2014, page 10-11

- reduction in financing and insurance costs.

This transaction will also result in the eventual elimination of 145 Long-Term Load Transfers (**"LTLT"**) (128 between HCHI and Hydro One and 17 between HCHI and Hydro One Norfolk), thereby resulting in avoiding the need for related capital expenditures.

Quantitative Efficiencies

Quantitative efficiencies arise in three principal areas:

- Local area operating and capital savings resulting from a more efficient distribution system due to the elimination of an artificial electrical border (i.e., benefits from contiguity);
- Savings due to the elimination of redundant administrative and processing functions (i.e., back-office savings or scale efficiencies); and
- Lower overall debt costs upon refinancing HCUI's current higher-cost debt assumed in the transaction, further enhanced by the reduced capital expenditure requirements.

Contiguity Benefits

It should be noted that HCHI is embedded in Hydro One's service territory. With the elimination of the service boundary between the two utilities and with the recent acquisition of Norfolk Power, Hydro One will have accountability for planning the electricity needs for the entire region, which will allow for more rational, efficient and effective planning and development of the distribution system.

Hydro One's existing service territory is situated immediately adjacent to the territory served by HCHI and the recently approved transaction with Norfolk Power. The geographic advantage of contiguity allows for economies of scale to be realized at the field or operational level through the integration of HCHI's and Hydro One's local systems. These operational economies of scale may not be available at all, or to the same extent, to other would-be purchasers who do not have the same advantage of contiguity.

Contiguity benefits will occur where artificial electrical borders exist. This situation is common throughout the Province and is shown in the attached map (see **Attachments 3a and 3b**) depicting the current checkerboard pattern of the local distribution system, with small- and medium-sized LDCs contiguous to or surrounded by Hydro One.

With the elimination of an artificial electrical border between contiguous distributors, operational efficiencies may arise in various areas, resulting from the ability to: rationalize local space needs through the elimination or repurposing of duplicate facilities, such as service centres; more efficiently schedule operating and maintenance work and dispatch crews over a larger service area; and more efficiently utilize work equipment and optimize assets (e.g., trucks and other tools), leading to lower capital replacement needs over time. The elimination of the electrical border allows for more rational and efficient planning and development of the distribution system and at the same time reduces the need to expend capital in order to eliminate the existing long term load transfers between the LDCs. All of the above provide the potential to result in operating and capital savings, both immediate and over time, which will provide long-term benefits to ratepayers, relative to the status quo.

Savings from Economies of Scale

A larger customer base resulting from the creation of a larger regional distributor leads to costs for processing systems, such as billing, customer care, human resources and financial, being spread over a larger group of customers. Consolidation of these functions is also expected to result in efficiency benefits as duplicate systems and staff positions are eliminated, leading to lower capital and operating costs over time. In addition, administrative savings arising from the elimination of duplicate senior management and administrative functions are also achievable.

Hydro One's cost of borrowing is typically lower than that of local LDCs, leading to savings in financing costs over time. These savings arise from Hydro One's ability to refinance HCUI debt upon maturation at a lower rate and from the expectation that there will be capital savings over time, which in turn are anticipated to lead to a reduced rate base and lower debt and equity return costs relative to the status quo.

Efficiency and Quantitative Savings in the Haldimand Context

Hydro One will maintain the existing HCHI Operating Centre located in Caledonia and will add a new satellite operating centre located in Dunnville. Hydro One serves customers in the neighbouring operating areas of Dundas, Simcoe, and Lincoln surrounding Haldimand County and thus has crews that travel some of the same roads and drive by some of the same facilities as the existing line crews from HCHI. Staff in the Hydro One Field Business Centre in Dundas answer calls from local businesses and customers for operational services just outside Haldimand County served by Hydro One in the Simcoe, Dundas and Lincoln Operating Areas. HCHI has customer service representatives that carry out similar functions for their neighbouring customers within Haldimand County. Rationalizing these functions over a larger service area, including Norfolk Power, will yield efficiency savings.

As mentioned earlier, contiguity savings are expected through more efficient system planning by the elimination of artificial electrical borders between Hydro One, HCHI, and Norfolk Power. This allows efficiency gains to be realized through the elimination of duplicate administrative and transaction-processing functions. For example, Hydro One processes financial, human resource, information technology, and work management transactions for work being conducted in its contiguous service area with Haldimand County. HCHI processes very similar transactions for its own service area in Haldimand County. Therefore, Hydro One has the opportunity to eliminate these sources of duplication if the transaction proceeds. For example, the functions performed by senior management would be eliminated, and the HCHI Board of Directors would no longer be required, representing savings of over $750,000 per year. Further, there is an opportunity to reduce the number of regulatory filings, CDM program administration costs, vehicle fleet and information technology costs, and the use of external consultants and contractors.

The efficiencies attained through some of the activities discussed above, result in Hydro One's expectation to be able to consolidate 36 of the 52 positions, currently required to operate HCHI, into positions in Hydro One that would otherwise need to be filled due to retirements and attrition. As Hydro One already has an operating organization in place that provides the same functions (such as senior management, professional, and some union staff), certain positions will no longer be required to serve HCHI.

The HCHI personnel currently in these roles will have the opportunity to transition to other positions within the Hydro One organization. As Hydro One is facing significant demographic challenges and upcoming retirements, it is able to provide job security for HCHI staff, leveraging their expertise and industry knowledge, and will utilize both its existing staff and those acquired from HCHI to meet the needs of all its customers. As Hydro One will now be planning the electricity needs for Haldimand and Norfolk Counties, it will be able to more efficiently manage both the operating and capital costs associated with serving customers across the region.

Table 1 below shows Hydro One's projection, by staff category, of the number of staff that are currently employed by HCHI and their respective aggregate salaries. HCHI direct staff will be integrated into Hydro One's operations and will become part of the pool of resources working on everything within the larger service area encompassing HCHI's current service territory. Indirect staff are those staff that are expected to move to other positions within Hydro One once integration is complete. The left side of Table 1 breaks down the current staff between direct and indirect positions and shows the total salary paid by HCHI. The right-hand side of Table 1 illustrates the anticipated level of staffing and salaries required to operate the current HCHI service territory once acquired by Hydro One and operated as the Haldimand business segment.

Table 1

	HCHI Staffing and Salaries			Proposed Hydro One Haldimand Staffing and Salaries	
Staff Category	Direct	Indirect	Salary($)	Direct	Salary ($)
Management and Professional		16	1,401,605		
Inside Union		12	572,972		
Outside Union	16	8	1,604,990	16	1,661,267
Total	16	36	3,579,568	16	1,661,267
Projected Salary Savings					**$1,918,302**

Table 1 demonstrates that Hydro One anticipates overall salary savings of approximately $1.9 million annually, after accounting for differences between salary levels between HCHI and Hydro One.

This transaction will also achieve capital expenditure savings. Hydro One utilizes an ARA process. This process determines the state of Hydro One's distribution system, identifies current asset needs, and creates a line of sight to future needs, which enables an in-depth view of asset risk, and improved decision-making. The ARA incorporates field asset assessment, including visual inspections and evaluation. This process allows Hydro One to assess the state of its assets and assess the risks that those assets pose and to develop appropriate plans in order to ensure reliability and service quality are met. This assessment considered the state of the HCHI distribution system, identified current asset needs, and created a line of sight to future asset needs. Using the ARA process has enabled Hydro One to project the HCHI OM&A and capital expenditure requirements and the resulting potential savings.

Based on the quantitative factors discussed above, Hydro One has provided a comparative cost structure analysis for the proposed transaction relative to the status quo, extending out ten years (see **Table 2**). Three scenarios are presented in Table 2 with respect to efficiency savings associated with Hydro One operating in the HCHI service territory under the proposed acquisition. The medium scenario represents a *base case* and compares expenditures based on Hydro One's estimate of HCHI's status quo operations with Hydro One's forecast of HCHI's operations under its ownership. The high and low scenarios illustrate a plus/minus 20% variation on Hydro One's forecast, based on its ownership of HCHI.

Financing savings are also expected to be achieved as a result of both a lower Hydro One cost of debt upon refinancing of some or all of the debt assumed in the transaction, and lower capital replacement needs over time. These savings are not currently conducive to quantification due to uncertainty related to the timing of refinancing and the size of the spread that will prevail when refinancing occurs.

Table 2: Projected LDC Acquisition OM&A and Capital Expenditure Savings

$M	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
OM&A										
Status Quo Forecast	8.2	8.3	8.5	8.6	8.8	8.9	9.1	9.3	9.4	9.6
Hydro One Forecast	6.4	4.4	4.5	4.6	4.8	4.9	5.0	5.1	5.2	5.2
Projected Savings	1.8	4.0	4.0	4.0	3.9	4.0	4.1	4.2	4.2	4.3
Projected Savings [1]										
Lower OM&A, Higher Savings Scenario	3.1	4.8	4.9	4.9	4.9	5.0	5.1	5.2	5.2	5.4
Projected Savings [2]										
Higher OM&A, Lower Savings Scenario	0.5	3.1	3.1	3.1	3.0	3.0	3.1	3.2	3.2	3.3
Capital										
Status Quo Forecast	6.4	6.1	5.4	5.6	5.3	5.4	5.5	5.5	5.6	5.7
Hydro One Forecast	4.2	3.2	3.3	3.4	5.9	3.9	4.0	4.0	4.1	4.2
Projected Savings	2.2	2.9	2.1	2.2	(0.6)	1.5	1.5	1.5	1.5	1.6
Projected Savings [1]										
Lower Capital, Higher Savings Scenario	3.0	3.5	2.8	2.8	0.6	2.2	2.3	2.3	2.4	2.4
Projected Savings [2]										
Higher Capital, Lower Savings Scenario	1.4	2.2	1.4	1.5	(1.8)	0.7	0.7	0.7	0.7	0.7

[1] Low case scenario based on a 20% reduction in costs from Hydro One Forecast

[2] High case scenario based on a 20% increase in costs from Hydro One Forecast

As per EB-2013-0134, HCHI has 13 customers per kilometre in its overall service territory, with a 2014 forecast OM&A cost of $385/customer/month. This is comparable to Hydro One’s average 2015 forecast OM&A cost of $275/customer/month, which applies to R1 rate class customers in communities with a customer density of at least 15 customers per kilometre. As such, it is reasonable to believe that Hydro One’s cost to serve HCHI’s customers would be less than HCHI’s current costs of serving its customers.

Qualitative Efficiencies

Qualitative benefits and efficiencies are also anticipated from the acquisition and integration of a smaller LDC, like HCHI, with Hydro One. Some of these benefits may include:

- Continued employment for all staff of acquired LDCs - Although duplicate functions performed by staff will be eliminated as part of the integration process leading to efficiency gains, Hydro One, due to its size and current staff retirement profile, is able to offer continued employment to staff of acquired LDCs. This is a benefit that smaller would-be acquirers may not be able to offer;
- Enhanced call centre service to customers – Hydro One has a sophisticated call-centre operation which offers 24/7 live outage reporting as well as web and Twitter access which both utilities customers can access. In addition, Hydro One has launched a highly successful and popular smart-phone application for real-time outage management that customers can download to their devices, allowing instant access to outage information and estimated restoration times. Hydro One was recognized by the International Association of Business Communicators (**“IABC”**) as the 2013 recipient of two Gold Quill awards and the Jake Wittmer Research Award for the launch of Hydro One's mobile application;
- Savings in recruitment, training, and staff development costs are expected as the transaction will allow trained and experienced utility staff to continue to be available within the Hydro One organization arising due to expected retirements and other attrition;

- Industry benefits are also expected to accrue to various agencies within the Ontario energy industry. For example, the costs to regulate and administer the sector may be reduced as this and further acquisitions are completed. The Ontario Power Authority, the Independent Electricity System Operator, the OEB, and Ministry of Energy can achieve potential savings through reduced regulatory burden and industry oversight. Further, enhanced regional planning efficiencies could also be achieved by having fewer distribution companies planning for larger areas where capital can be deployed more efficiently and effectively than with the current fragmented approach.

1.2 Price of Electricity Service

The proposed transaction protects HCHI customers through a commitment to freeze base electricity distribution delivery rates for a period of five years from closing of this transaction. In addition, HCHI is seeking approval to implement a negative rate rider that will result in a further 1% reduction from the 2014 base delivery rates as approved by the OEB in EB-2013-0134. The cost of providing this rate rider will be recovered from synergies that are generated from consolidating HCHI's operations into Hydro One.

The proposed transaction also protects Hydro One's customers. Hydro One filed a five-year cost of service rate application (EB-2013-0416) on December 19, 2013, for rates effective 2015 to 2019 under the Board's Custom Incentive Regulation regime. That application was based on Hydro One's existing customer base: in other words, it did not include any capital or OM&A costs associated with serving customers, and/or maintaining or operating assets in the service territory of any acquired LDC, including HCHI. As such, this transaction will not impact Hydro One's existing customers with respect to price. In the long term, because the company's fixed costs of operations will be spread over a wider customer base, Hydro One's existing customers are expected to obtain a small price benefit.

1.2.1 Bill Impact

Below are the estimated bill impacts, for customers in the HCHI service territory, of the proposed transaction on the total bill as well as distribution base rates, in order to give effect to the proposed negative rate rider. The impacts are based on HCHI's current rates applied to the average consumption levels for each rate class used by HCHI in calculating bill impacts as part of its 2014 Cost of Service application, and approved by the OEB. The rate reductions vary slightly from the 1% reduction as a result of rounding errors (using two decimal places for fixed charges and four decimal places for volumetric charges).

Table 3

	Change in Base Distribution Rates (%)	**Change in Total Bill (%)**
Residential	-0.89	-0.24
General Service less than 50 kW	-1.02	-0.22
General Service 50 to 4999 kW	-0.96	-0.07
Embedded Distributor	-1.00	-0.04
Unmetered Scattered Load	-0.95	-0.25
Sentinel Lighting	-0.99	-0.69
Street Lighting	-1.03	-0.56

Detailed calculations of the bill impacts can be found in **Exhibit A, Tab 3, Schedule 1, Attachment 14.**

1.2.2 Regulatory Assets and Rate Riders

In addition to the rate rider to reduce base distribution delivery rates, Hydro One requests approval to extend the existing HCHI funding adder for renewable energy generation to be in effect until the effective date of the next cost of service application.

The HCHI Regulatory Assets currently approved by the OEB will continue to be tracked in their respective accounts and disposition will be sought at a future date.

1.2.3 Rate Schedules

The proposed rate schedules, including the requested rate rider, for the area currently served by HCHI, effective after closing, are filed as **Exhibit A, Tab 3, Schedule 1, Attachment 15.**

1.3 Adequacy, Reliability and Quality of Electricity Service

Hydro One will endeavour to maintain or improve reliability and quality of electricity service for all of its customers. As part of the proposed transaction, Hydro One will retain local knowledge and expertise from existing HCHI staff. This local knowledge and expertise will be leveraged through greater coordination with Hydro One's regional operations and staff, which will allow Hydro One to maintain or improve reliability and quality of electricity service. Hydro One has committed to meet or exceed specific service levels for reliability and customer service (see **Section 6.5 of Attachment 6**). With respect to reliability, HCHI existing customers will have specific assurances given that the Share Purchase Agreement (the **"Agreement")** stipulates that if, at any time during the period beginning on the closing date and continuing for the five years following closing date, the five-year rolling average for reliability in HCHI's pre-closing territory falls below the average reliability reported by HCHI to the OEB for the five years prior to closing, Hydro One shall make a payment to the Corporation of Haldimand County in the amount of $100,000 to be used for charitable or other community interests in Haldimand County. Hydro One will be aided in achieving these results by retaining the direct staff from HCHI as part of its local operations. This will allow Hydro One to retain local knowledge and skills to ensure that it meets its service quality obligations.

Hydro One plans to maintain the existing HCHI operating centre located in Caledonia and has committed to adding a satellite operating centre in the Dunnville area. The two operating centres will allow Hydro One to further consolidate its operations and staff in the Simcoe, Lincoln, and Dundas operating areas, resulting in 30 additional full-time equivalent staff resources located within Haldimand County. This combined, local operating presence, with reduced distance to travel, will support Hydro One's ability to deliver reliable service. These changes will be made to balance the requirements of Hydro One's existing customers in the surrounding operating areas along with the new customers to serve in Haldimand County. By optimizing the utilization of existing Hydro One assets and the acquired capabilities of Haldimand County Hydro, Hydro One believes that service levels will be maintained or improved for all customers. Further, there will be no material difference between the distribution network from the day before the transaction closes and the day after. The same distribution facilities will be in place. The key difference will be that staff will be located closer to the customers in Haldimand County and the local staff familiar with the local assets will remain part of the team to maintain the distribution system. This, combined with the fact that planning will be done on a consolidated basis across Norfolk and Haldimand Counties, should result in the same or improved level of service.

Attachment 3c shows that Hydro One's existing operations (including Norfolk Power) surrounding Haldimand County, including the Simcoe, Dundas, and Lincoln Operating Areas, already serve the geographic area surrounding HCHI**.** As mentioned, following the approval of this Application, there will be a new facility in Haldimand County which will serve as a satellite operating centre increasing the number of resources available to respond to outages. HCHI is embedded in Hydro One's service territory. With the elimination of the service boundary between the two utilities and the recently-acquired Norfolk Power, Hydro One will have accountability for planning the electricity needs for the entire region, allowing for more rational, efficient and effective planning and development of the distribution system.

The existing reliability metrics for HCHI and the local metrics for Hydro One for comparable conditions are provided in **Table 4** below.

Table 4

	2011	2011	2012	2012	2013	2013
	Hydro One	Haldimand Hydro[2]	Hydro One	Haldimand Hydro	Hydro One	Haldimand Hydro
Excluding LOS[3]						
Duration (SAIDI)	6.43	8.34	3.28	2.22	6.93	9.69
Frequency (SAIFI)	2.59	3.30	1.24	1.17	2.44	2.57

Based on reliability statistics for 2011 through to 2013, Hydro One customers in the vicinity of Haldimand County experienced a comparable level of service in terms of duration and frequency of interruptions in comparison to HCHI customers. Hydro One anticipates that reliability will in fact improve through the combination of the satellite operating centre and broad staff resources being optimized in Haldimand County.

Hydro One has committed to use commercially reasonable efforts to meet the aggregate capital expenditure budget as set forth in the Agreement (see **Attachment 6**), thereby allowing Hydro One to maintain or improve reliability from the current performance level achieved by HCHI. Please see **Section 1.1** of this exhibit for more information on the capital forecast.

Hydro One has also agreed to establish an Advisory Committee to provide a customer-focused forum for communication between Hydro One and the Vendor. Under the terms of the Agreement, the Vendor may appoint at least three representatives to the committee, and Hydro

[2] Data-source is the OEB Yearbook
[3] Loss of Supply ("LOS") interruptions attributable to assets that are not part of the Hydro One Distribution System or the HCHI Distribution System

One will include staff representation from the same geographic district covered by HCHI's current distribution licence.

In the long term, HCHI customers are expected to benefit from operational efficiencies expected by having the HCHI assets integrated into Hydro One's larger distribution system. Scale efficiencies are expected in the areas of operating and maintaining the distribution system, planning capital replacement and the overhead and management functions.

1.4 Conservation and Demand Management, Smart Grid and Promotion of Renewable Energy Sources

Currently HCHI has delivered its own programs related to Conservation and Demand Management, Smart Grid, and the Promotion of Renewable Energy sources. To achieve further synergies from the transaction, Hydro One will rationalize these programs with its own. There may also be opportunities to rationalize programs across the other acquired LDCs that Hydro One has acquired or will acquire. Each LDC is mandated to have its own initiatives in these areas, so there are opportunities for program consolidation. This may include areas where an LDC can offer unique capabilities or experience that can provide a positive impact on Hydro One's programs going forward. For example, HCHI, Woodstock Power and Norfolk Power all have significant Geographic Information Systems (**"GIS"**) in place, which will allow for ready integration of their assets into Hydro One's asset management systems and processes. These benefits are qualitative in nature, but represent examples of synergies that support the underlying objectives of the Board related to these three areas at no additional cost to customers.

1.5 Additional Sector Support of Consolidation

There are recognized efficiencies from sector consolidation. The Ontario Distribution Sector Review Panel, "Renewing Ontario's Electricity Distribution Sector: Putting the Customer First", supported distributor consolidation:

> *The Panel is supporting consolidation not as an end, but as a means to an end. The current fragmented nature of Ontario's electricity distribution system, with its large number of small distributors, is a barrier to the innovation that is needed in the sector, and that its customers deserve. It is also an obstacle in the way of the most cost-effective delivery of electricity.*[4]

The Commission on the Reform of Ontario's Public Services, "A Path to Sustainability and Excellence" (the **"Drummond Report"**) recommended that the Province:

> *Consolidate Ontario's 80 local distribution companies (LDCs) along regional lines to create economies of scale. Reducing the $1.35 billion spent on operations, maintenance and administrative costs for Ontario's LDCs would result in direct savings on the delivery portion of the electricity bill.*[5]

The OEB's Decision in RP-2003-0044 also recognized that further efficiencies are gained with the elimination of artificial electrical borders between contiguous distributors. In RP-2003-0044, although the context for the Board's Findings in that case was in relation to service area amendment (**"SAA"**) applications, the principles adopted by the Board may apply equally to merger situations, as noted below:

[4] Ontario Distribution Sector Review Panel Report, page 27
[5] Drummond Report, page 331

> *The promotion of economic efficiency in the distribution sector is one of the Board's guiding objectives in the regulation of the electricity sector. The Board is persuaded that economic efficiency should be a primary principle in assessing the merits of a service area amendment application. Economic efficiency would include ensuring the maintenance or enhancement of economies of contiguity, density and scale in the distribution network; the development of smooth, contiguous, well-defined boundaries between distributors; the lowest incremental cost connection of a specific customer or group of customers; optimization of use of the existing system configuration; and ensuring that the amendment does not result in any unnecessary duplication or investment in distribution lines and other distribution assets and facilities.* [Para. 84]

A core difference in assessing the economic efficiency of a merger or acquisition versus a SAA is that in an SAA application, which typically deals with a request to serve new connecting customers in an adjacent service area, the lower incremental cost to connect is a key consideration in assessing the merits of the application, as noted in the excerpt from the RP-2003-0044 Decision above. In a merger or acquisition, net ratepayer and system benefit, relative to the status quo, based on the no-harm test, rather than lower incremental cost to serve, is the key factor in determining whether the transaction is in the public interest.

The completion of this transaction provides an example where significant efficiency gains may be realized by a merger or acquisition between a large contiguous distributor, like Hydro One, and a smaller adjacent LDC, like HCHI.

1.6 Incremental Transaction Costs

Both parties to the transaction will have incurred some incremental costs associated with completing the transaction. These include costs incurred for due diligence to negotiate and complete the transaction, the integration costs to transfer the customers into Hydro One's customer and outage management systems, and initial costs to standardize equipment. These costs will be offset through productivity gains associated with the transaction and will not be included in Hydro One's revenue requirement. There will not, therefore, be any additional costs to ratepayers.

These incremental costs are estimated to be between \$2.5 million to \$4 million. All of these costs are expected to be incurred during the rate freeze period and will be offset through the productivity gains achieved during this time period.

2.0 TIMING OF REBASING AND RATE HARMONIZATION

Hydro One proposes to defer the rate rebasing of the former HCHI to the earliest opportunity after five years from the date of closing the proposed transaction. This was an important factor in Hydro One's consideration of the merits of the proposed transaction. The deferral of rebasing Hydro One Haldimand will give Hydro One time to retain savings to offset costs while protecting the interests of consumers across both existing service areas. This approach is consistent with the policy described in the Board's Report entitled "Rate-making Associated with Distributor Consolidation".

As industry rates evolve over the next five-plus years, Hydro One expects to file a rate application consistent with OEB rate-making principles (e.g. fair, practical, clear, rate stability and effective cost recovery of revenue requirement) in line with the principles noted above. The rate application at that time may propose: (i) to create new acquired customer rate classes; (ii) to move acquired customers to an appropriate Hydro One rate class existing at that time; or (iii) some other option. It is not possible today to say which of these approaches will be adopted as it will depend on the situation at the time of setting the new rates for Hydro One Haldimand. The approach will consider the bill impact on both legacy and acquired customers. Some considerations in deciding on rate strategies include the number and characteristics of the acquired utilities, customer growth in the acquired utilities, and potential development within the electricity regulatory arena in Ontario.

Whichever approach is adopted for setting the rates of acquired utilities, any future proposed rate applications will be subject to OEB approval, satisfy the Board's "Filing Requirements for Electricity Distribution Rate Applications", and reflect the actual cost to serve these customers, including the anticipated productivity gains resulting from this consolidation.

Until the end of the five-year freeze period, Hydro One proposes to retain separate rate schedules for customers in each of the service areas – i.e. those currently served by Hydro One and those currently served by HCHI.

3.0 USGAAP

HONI Transmission received OEB approval to utilize US Generally Accepted Accounting Principles (**"USGAAP"**) as its approved framework for rate setting, regulatory accounting and regulatory reporting in the Decision with Reasons in EB-2011-0268 (issued on November 23, 2011). Hydro One also received OEB approval to use USGAAP in EB-2011-0399 (issued on March 23, 2012). The latter Decision noted "as the Board has found that Hydro One transmission rates should be set on the basis of USGAAP, it would generally be inefficient to require the distribution utility to use MIFRS for regulatory reporting and rate making". In addition, in the recent Norfolk Decision and Order, the Board decided that using USGAAP methodology in accounting for Norfolk Power Distribution Inc. (the acquired utility) will be more efficient than continuing to use MIFRS methodology.

HCHI's financial statements are currently prepared under Canadian Generally Accepted Accounting Principles (**"CGAAP"**) and are compliant with the OEB letter (July 17, 2012) requiring all LDCs retaining CGAAP to adopt IFRS-compliant depreciation policy and an IFRS-compliant cost capitalization policy.

Hydro One requests approval to utilize USGAAP for accounting purposes in relation to Hydro One Haldimand. Approval to use USGAAP for Hydro One Haldimand will simplify any future rate integration, avoid incremental costs or productivity losses by simplifying processes and avoiding the need for workarounds, and facilitate Hydro One Inc.'s consolidated reporting for securities filing purposes (including future U.S. Securities and Exchange Commission), thereby avoiding incremental costs and/or reduced productivity. By using one uniform standard of reporting, Hydro One seeks to achieve integration and scale efficiencies. Given the relatively small size of the HCHI operations (when compared to Hydro One's), Hydro One submits, and HCHI supports that it would be inefficient and costly to maintain two equally robust, yet distinct, accounting regimes for divisions within Hydro One.

4.0 COMPLIANCE MATTERS

Pending approval of this transaction, and after notification to the Board that integration is completed, HCHI's distribution system, Electricity Distribution Licence ED-2002-0539, and Rate Order will be transferred to Hydro One. The customers, assets, systems, processes and operations of HCHI will be fully integrated into Hydro One's business activities.

Hydro One confirms that it is materially in compliance with its regulatory requirements, subject to any approved regulatory exemptions. The list of specific code requirements from which

Hydro One has been exempted can be found in Schedule 3 of Hydro One's Electricity Distribution Licence.

HCHI has confirmed that as of the date of the Application, to the best of its knowledge, it is in compliance with all relevant licence and code requirements per its Electricity Distribution Licence (ED-2002-0539). It is expected that following the approval and completion of the transaction and after the integration of the HCHI distribution business activities with those of Hydro One, Hydro One will continue to be materially compliant with all applicable legislation, regulations, Market Rules, and other Licence conditions, Rules and Codes.

Hydro One's compliance policy will continue to require that confirmed instances of non-compliance be disclosed and mitigated as necessary including applications for exemptions from such requirements, if necessary. Any potential instances of non-compliance associated with HCHI's distribution business activities will be addressed during the integration process. For example, the non-electricity billing services currently being provided by HCHI affiliates to the Corporation of Haldimand County may be transferred to Hydro One Telecom Inc. This transfer, if completed, will be implemented after a short transition period, in compliance with Section 71(1) of the Act. In any case, given the small customer base of HCHI (when compared to Hydro One), the integration is not expected to have any material impact on the current compliance status of Hydro One, even during the transition period.

During the period after closing of the transaction and prior to full integration, service level agreements in compliance with the OEB's *Affiliate Relationships Code for Electricity Distributors and Transmitters* will be drafted between HCHI and Hydro One affiliates.

Hydro One will keep separate financial records for HCHI. Upon integration, HCHI's assets will be transferred to Hydro One and tracked as a separate business unit within Hydro One. OM&A costs will be charged to the HCHI business unit similar to what is now done to record costs between Hydro One's Transmission and Distribution businesses. Common costs will be allocated to the HCHI business unit, consistent with Hydro One's current common corporate cost allocation model.

5.0 SUMMARY – COMPLIANCE WITH THE "NO HARM TEST" AND SECTION 1 OF THE OEB ACT, 1998

For the reasons addressed in the preceding sections, both qualitative and quantitative savings and efficiencies are expected to result from this transaction. Overall, Hydro One's analysis shows the synergies that will accrue as a result of this transaction will be to the benefit of ratepayers. These attributes allow Hydro One and HCHI to conclude that the transaction will not cause harm to ratepayers, and indeed will provide benefits to its ratepayers in the long term. Moreover, this application embodies the current regulatory policies and principles of the Board in pursuing the objectives established by section 1 of the Act.

Ontario Energy Board

Application form for Applications under Section 86 of the *Ontario Energy Board Act, 1998*

PART I: GENERAL INFORMATION

1.1 Nature of Applications:

(A) Under section 86(2)(b), the applicant is Hydro One Inc. (the "Purchaser" or "HOI") and the other party is The Corporation of Haldimand County (the "Vendor" or "Haldimand County"), regarding the acquisition by HOI of all of the shares of Haldimand County Utilities Inc. ("HCUI"), the parent company of the distributor Haldimand County Hydro Inc. ("HCHI"); and

(B) Under section 86(1)(a), HCHI applies for leave to transfer its distribution system to Hydro One Networks Inc.'s ("Hydro One") distribution company;

1.1.1 Application Type

☒ For leave for a transmitter or distributor to sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety (section 86(1)(a))

☐ For leave for a transmitter or distributor to sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public (section 86(1)(b))

☐ For leave for a transmitter or distributor to amalgamate with any other corporation (section 86(1)(c))

☐ For leave for a person to acquire voting securities that will exceed 20% of a distributor or transmitter (section 86(2)(a))

☒ For leave for a person to acquire control of a company that holds more than 20% of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of the corporation (section 86(2)(b))

1.1.2 Notice under section 80 or 81 of the Act

Is a notice of proposal required under section 80 or 81 of the Act?

☐ Yes

☒ No

If yes, the applicant must also file a completed "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the *Ontario Energy Board Act, 1998*" with the Board.

1.2 Identification of the Parties

1.2.1 Name of Applicant

Legal name of the applicant: Hydro One Inc. ("HOI")

Name of Primary Contact:

Salutation	Last Name	First Name	Initial
Mr. ☒ Mrs. ☐ Miss ☐ Ms. ☐ Other ☐	Engelberg	Michael	

Title/Position: Assistant General Counsel

Address of Head Office: 483 Bay Street, South Tower, 8th Floor

City	Province/State	Country	Postal/Zip Code
Toronto	Ontario	Canada	M5G 2P5

Phone Number	Fax Number	E-mail Address
(416) 345-6305	(416) 345-6972	mengelberg@HydroOne.com

Name of Primary Contact:

Salutation	Last Name	First Name	Initial
Mr. ☐ Mrs. ☐ Miss ☐ Ms. ☒ Other ☐	Henderson	Erin	

Title/Position: Senior Regulatory Coordinator

Address of Head Office: 483 Bay Street, South Tower, 7th Floor

City	Province/State	Country	Postal/Zip Code
Toronto	Ontario	Canada	M5G 2P5

Phone Number	Fax Number	E-mail Address
416-345-4479	(416) 345-6972	regulatory@HydroOne.com

Legal name of the applicant in (B): Haldimand County Hydro Inc.. 1 Greendale Drive

Name of Primary Contact:

Mr. ☐ Mrs. ☐	Last Name	First Name	Initial
Miss ☐ Ms. ☒	Albert	R. Jane	
Other ☐ ______	Title/Position		
	President and CEO		

Address of Haldimand County Utilities Inc. (**"HCUI"**), 1 Greendale Drive

City	Province/State	Country	Postal/Zip Code
Caledonia	Ontario	Canada	N3W 2J3
Phone Number	**Fax Number**	**E-mail Address**	
905-765-5211	905-765-5316	jalbert@hchydro.ca	

Address of Primary Contact for HCHI in relation to s. 86(2) application: Norton Rose Fulbright Canada LLP, Royal Bank Plaza, 200 Bay Street, Suite 3800,P.O. Box 84, Toronto, ON M5J 2Z4.

Mr. ☐ Mrs. ☐	Last Name	First Name	Initial
Miss ☐ Ms. ☒	DeMarco	Elisabeth	
Other ☐ ______	Title/Position		
	Counsel		

City	Province/State	Country	Postal/Zip Code
Toronto	Ontario	Canada	M5J 2Z4
Phone Number	**Fax Number**	**E-mail Address**	
(416) 203-4431	(416) 216-3930	Elisabeth.Demarco@nortonrosefulbright.com	

Other Party to the Transaction (if more than one attach a list)
Name of the other party: The Corporation of Haldimand County

Name of Primary Contact:

Mr. ☒ Mrs. ☐	Last Name	First Name	Initial
Miss ☐ Ms. ☐	Hewitt	Ken	
Other ☐ ______	Title/Position		
	Mayor		

Address of Head Office: 45 Munsee Street North

City	Province/State	Country	Postal/Zip Code
Cayuga	Ontario	Canada	N0A 1E0

Phone Number	Fax Number	E-mail Address
(905) 318-5932	(905) 772-2148	khewitt@haldimandcounty.on.ca

Name of the other party: Hydro One Networks Inc.

Name of Primary Contact:

Mr. ☐ Mrs. ☐
Miss ☐ Ms. ☒
Other ☐ ____________

Last Name	First Name	Initial
Henderson	Erin	

Title/Position: Sr. Regulatory Coordinator

Address of Head Office: 483 Bay Street, South Tower, 7th Floor

City	Province/State	Country	Postal/Zip Code
Toronto	Ontario	Canada	M5G 2P5

Phone Number	Fax Number	E-mail Address
(416) 345-6948	(416) 345-5866	regulatory@HydroOne.com

1.3 Description of the Business of Each of the Parties

1.3.1 Please provide a description of the business of each of the parties to the proposed transaction, including each of their affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity ("Electricity Sector Affiliates").

Haldimand County Hydro Inc. ("HCHI")

HCHI owns and is responsible for the operation, maintenance and management of the assets associated with the distribution of electrical power and energy within its service territory, as specified in Distribution Licence ED-2002-0539 (a copy of which is provided in **Exhibit A, Tab 3, Schedule 1 Attachment 1**).

HCHI is, at the date of this application, a wholly-owned subsidiary of Haldimand County Utilities Inc. (**"HCUI"**), a holding company, itself wholly-owned by the Corporation of Haldimand County.

Haldimand County Energy Inc. ("HCEI")

HCEI provides non-regulated water and sewer billing, collecting, and customer care services to the Corporation of Haldimand County, as well as sentinel lights rentals to its residents.

HCEI is, at the date of this application, a wholly-owned subsidiary of HCUI.

Hydro One Inc. ("HOI")

Hydro One Inc. is wholly-owned by the Province of Ontario and is the parent company of Hydro One Networks Inc., 1908872 Ontario Inc., Hydro One Brampton Networks Inc., Hydro One Remote Communities Inc., Norfolk Power Distribution Inc. and Hydro One Telecom Inc.

Hydro One Networks Inc. ("Hydro One")

Hydro One is a wholly-owned subsidiary of HOI and is the largest transmitter and distributor of electricity in Ontario. Hydro One's distribution company serves approximately 1.2 million customers. Customers include local distribution companies, customers with load exceeding 5 MW, and rural and urban customers. Distribution assets as at December 31, 2013, had a net book value of $5.6 billion. Hydro One owns and is responsible for the operation, maintenance and management of the assets associated with the distribution of electrical power and energy within its service territory, as specified in Distribution Licence ED-2003-0043 (a copy of which is provided in **Exhibit A, Tab 3, Schedule 1, Attachment 2**). Hydro One also has a regulated transmission business owning 97% of transmission in Ontario with almost 30,000 km of high-voltage transmission lines.

Hydro One Inc. – Norfolk Power Distribution Inc.

Hydro One Inc. – Norfolk Power Distribution Inc. owns and is responsible for the operation, maintenance, and management of the assets associated with the distribution of electrical power and energy for approximately 23,000 customers in both urban and rural areas of Norfolk County. Hydro One recently acquired all issued and outstanding shares of Norfolk Power Distribution Inc., as approved by the OEB in EB-2013-0196/EB-2013-0187/EB-2013-0198.

Hydro One Brampton Networks Inc.

Hydro One Brampton Networks Inc. is HOI's urban distribution company serving customers in the GTA.

Hydro One Remote Communities Inc.
Hydro One Remote Communities Inc. operates a small, regulated generation and distribution system serving remote communities across Northern Ontario that are not connected to Ontario's electricity grid.

HOI's other business segment is represented primarily by the operations of **Hydro One Telecom Inc.,** which markets dark and lit fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. The assets of this segment, including Hydro One Telecom Inc., constituted approximately $974 million of HOI's total assets of $22 billion as at December 31, 2013.

Note: The Share Purchase Agreement is structured between The Corporation of Haldimand County, 1908872 Ontario Inc. and Hydro One Inc. 1908872 Ontario Inc. was used to allow for tax-efficient integration of the two corporate structures. The shares held by 19088772 Ontario Inc. will be transferred to HOI after closing. As such, this OEB application has referenced the transaction as between HOI and the Corporation of Haldimand County.

1.3.2 Please provide a description of the geographic territory served by each of the parties to the proposed transaction, including each of their Electricity Sector Affiliates, if applicable.

Haldimand County Hydro Inc.

As defined in Schedule 1 to its Distribution Licence, HCHI serves the geographical territory described as follows (the "HCHI Service Territory"):

The Corporation of Haldimand County as defined in the Town of Haldimand Act, 1999,
(a) excluding the consumer located at 2330 Regional Road 3

Hydro One Networks Inc.

See Hydro One's Electricity Distribution Licence ED-2003-0043 (**Exhibit A, Tab 3, Schedule 1 Attachment 2**), Schedule 1 for a Definition of its Distribution Service Area.

The attached map **(Exhibit A, Tab 3, Schedule 1**, **Attachment 3a)** is a representation of Hydro One's distribution service territory. It is not a substitute for the written description in its Electricity Distribution Licence ED-2003-0043. The map is accurate where local distribution companies' ("LDC") boundaries conform to existing or former municipal boundaries but is only a best-efforts representation in locations where there have been annexations or, for other reasons, the LDC boundaries are different from current or former municipal boundaries.

1.3.3 Please provide a description of the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.

Haldimand County Hydro Inc.

HCHI's distribution system serves approximately 21,000 Residential and General Service customers in the HCHI Service Territory.

The following table provides a summary of the number of customers and connections by customer class for 2013:

Rate Class	Number of Customers
Residential	18,755
General Service < 50 kW	2,342
General Service 50 to 4,999 kW	159
Embedded Distributor	8
Street Lighting	2,987
Sentinel Lighting	516
Unmetered Scattered Load	68
Total	**24,835**

Hydro One Networks Inc. - Distribution

Hydro One's distribution system serves approximately 1.2 million customers in its Service Territory.

The following table provides a summary of the number of customers in each Hydro One rate class:

Rate Class	Number of Customers
Urban Density Residential (UR)	140,540
Medium Density Residential (R1)	412,455
Low Density Residential (R2)	367,107
Seasonal Residential	156,901
General Service Energy Billed (GSe)	98,776
General Service Demand Billed (GSd)	7,361
Urban Density General Service Energy (UGe)	10,577
Urban Density General Service Demand (UGd)	1,130
Street Lights	5,234
Sentinel Lights	37,506
Distributed Generation (DGen)	88
Sub Transmission (ST)	607
Total	**1,238,282**

1.3.4 Please provide a description of the proposed geographic service area of each of the parties after completion of the proposed transaction.

> If the Board grants approval to section 86(2)(b) as stated above, Hydro One requests that the Board grant leave to transfer HCHI's distribution licence in accordance with Section 18 of the *Ontario Energy Board Act, 1998,* to reflect the fact that the HCHI service territory will be operated and maintained by Hydro One.

1.3.5 Please attach a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

> Please refer to **Exhibit A, Tab 3, Schedule 1, Attachments 4 and 5** for corporate charts of the Purchaser and the Vendor at closing, respectively.

1.4 Description of the Proposed Transaction

1.4.1 Please provide a detailed description of the proposed transaction.

> On June 10, 2014, the Corporation of Haldimand County (the **"Vendor"**) and HOI, through its wholly-owned affiliate 1908872 Ontario Inc. (the **"Purchaser"**), entered into a share purchase agreement (the **"Agreement"**), under which the Vendor has agreed to sell, and the Purchaser has agreed to purchase, all of the issued and outstanding shares of HCUI (the **"Purchased Shares"**). The purchase price is $75.0 million, comprised of a cash payment of approximately $65.2 million for the Purchased Shares and the assumption of HCUI's short and long-term debt of approximately $9.8 million. The Agreement contemplates the transaction closing 90 days following the Parties' receipt of all required approvals, including Ontario Energy Board approval of this Application under sections 86(2) and 86(1) of the *Ontario Energy Board Act, 1998*.
>
> A redacted copy of the signed Agreement is attached hereto as **Exhibit A, Tab 3, Schedule 1, Attachment 6**. The Agreement contemplates the following items in addition to the sale of the Shares:
>
> (a) HCHI will apply to the OEB for approval to include a negative rate rider to HCHI's electricity rates (effective May 1, 2014) to reduce base delivery distribution rates by one per cent across all rate classes, and to have such reduced rates apply for the next five years (please see **Exhibit A, Tab 2, Schedule 1, Section 1.2** of this application for further details).
>
> (b) During the period in which the negative rate rider is in effect, Hydro One and HCHI intend to transfer HCHI's regulated distribution system assets so that they are owned by, integrated with, and form part of Hydro One's existing distribution system. The parties therefore seek to have HCHI's existing Electricity Distribution Licence ED-2002-0539, and Rate Orders, transferred to Hydro One. Asset transfer and integration steps are expected to occur within 18 months of the close of the Agreement.
>
> (c) Following the five year effective period for the negative rate rider, Hydro One expects to apply to harmonize HCHI's rates with Hydro One's revenue requirement. The rebasing and rate harmonization application is expected to take effect in 2020 and will be based on then-prevailing

forecast costs as discussed **Exhibit A, Tab 2, Schedule 1, Section 2.**

(d) The Purchaser or its affiliate shall offer all active employees of HCHI continued employment in Haldimand County for at least one year post-closing.

(e) The Purchaser and the Vendor shall establish an advisory committee (the "**Advisory Committee")** to provide a forum for communication between the Purchaser and the Vendor. In establishing the Advisory Committee, the Purchaser shall select representatives, including the local superintendent from Hydro One's Zone 2 or equivalent, in consultation with officials of the Vendor. The Vendor has the right to appoint at least three representatives to the Advisory Committee.

(f) If at any time during the period beginning on the closing date and continuing for the five years following closing date, the five-year rolling average for reliability in HCHI's pre-closing territory falls below the average reliability reported by HCHI to the OEB for the five years prior to closing, the Purchaser shall make a payment to the Vendor in the amount of $100,000 to be used to address charitable or other community interests in Haldimand County.

(g) The purchase price is subject to adjustment within 90 days following closing, for working capital, net fixed assets, and long-term debt, in accordance with the Agreement.

The rate base value of the assets to be transferred as a result of this transaction is approximately $52.3 million.

1.4.2 Please provide the details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.

As described in section 1.4.1, the total purchase price is $75 million, The Agreement outlines three types of adjustments to the purchase price: (i) working capital, (ii) net fixed assets, and (iii) long term debt, as defined in the Agreement. These adjustments will be calculated within 90 days following closing.

1.4.3 Please attach the financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.

Please refer to the following attachments to **Exhibit A, Tab 3, Schedule 1** for a copy of the audited financial statements for the past two most recent years:

- **Attachment 7** 2013 Hydro One Inc. Consolidated
- **Attachment 8** 2012 Hydro One Inc. Consolidated
- **Attachment 9** 2013 Hydro One Networks Inc. - Distribution
- **Attachment 10** 2012 Hydro One Networks Inc. - Distribution
- **Attachment 11** 2013 Haldimand County Hydro Inc.
- **Attachment 12** 2012 Haldimand County Hydro Inc.

> Note that although the Corporation of Haldimand County is a party to this transaction, its financial statements have not been included, as they are not relevant to the transaction.

1.4.4 Please attach the pro forma financial statements for each of the parties (or if amalgamation, the one party) for the first full year following the completion of the proposed transaction.

> The proposed transaction will not have a material impact on Hydro One's financial position. The price is approximately 1% of Hydro One's Distribution's net fixed assets.

1.5 Documentation

1.5.1 Please provide copies of all annual reports, proxy circulars, prospectuses or other information filed with securities commissions or similar authorities or sent to shareholders for each of the parties to the proposed transaction and their affiliates within the past 2 years.

> HOI
>
> Information which HOI has filed to the Ontario Securities Commission is publicly available through SEDAR (www.sedar.com).
>
> HCHI
>
> This corporation does not file any material with securities commissions.

1.5.2 Please list all legal documents (including those currently in draft form if not yet executed) to be used to implement the proposed transaction.

> A redacted copy of the Agreement is provided in **Exhibit A, Tab 3, Schedule 1, Attachment 6**. Please note that the Agreement has been redacted to remove any "personal information" within the meaning of the *Freedom of Information and Protection of Privacy Act* (Ontario) and pursuant to section 42 of that Act such information should not be released publicly.
>
> A copy of the resolution of the Corporation of Haldimand County dated June 10, 2014 authorizing the sale of shares to Hydro One Inc. is provided as **Exhibit A, Tab 3, Schedule 1, Attachment 13**.

1.5.3 Please list all Board issued licences held by the parties and confirm that the parties will be in compliance with all licence, code and rule requirements both before and after the proposed transaction. If any of the parties will not be in compliance with all applicable licences, codes and rules after completion of the proposed transaction, please explain the reasons for such non-compliance. (Note: any application for an exemption from a provision of a rule or code is subject to a separate application process.)

> HCHI currently operates under Electricity Distribution Licence ED-2002-0539. Hydro One's Electricity Distribution Licence is ED-2003-0043.
>
> Please see **Exhibit A, Tab 2, Schedule 1 Section 4.0** for compliance related matters.

1.6 Consumer Protection

1.6.1 Please explain whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.

> As mentioned above, HCUI is a holding company, which is wholly-owned by the Corporation of Haldimand County. HCUI in turn wholly owns HCHI, a licensed electricity distributor. HOI's purchase of the shares from the Vendor (as described in section 1.4.1 and the Agreement) will therefore result in a change of control of HCUI, and consequently, a change in control of the distributor HCHI.

1.6.2 Please indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.

> As a result of the proposed transaction, HCHI is applying to the Board for approval to include a negative rate rider to HCHI's approved 2014 rates EB-2013-0134 to give effect to a 1% reduction to 2014 base electricity distribution delivery rates (exclusive of rate riders) (see **Exhibit A, Tab 2, Schedule 1, Section 1.2**). This would provide a benefit to HCHI ratepayers.
>
> The existing customers of Hydro One will also be held harmless from this transaction. Hydro One has applied for 2015-2019 rates under the Custom Incentive Ratemaking regime (EB-2013-0416). That application was based on Hydro One's existing customer base and did not include any capital or OM&A costs associated with serving customers and/or maintaining or operating assets for any acquired LDC, including HCHI. As such, there will be no impact on Hydro One's existing customers with respect to price. In addition, in the long term, because the fixed costs of operations will be spread over a wider customer base, Hydro One customers will see a small price benefit.
>
> Hydro One is committed to maintaining the quality, reliability and adequacy of electricity service in the current HCHI service territory. Please see **Exhibit A, Tab 2, Schedule 1 Section 1** for information on how this transaction provides consumer protection,

1.6.3 Please describe the steps, including details of any capital expenditure plans that will be taken to ensure that operational safety and system integrity are maintained after completion of the proposed transaction.

> Through the share acquisition described herein, the acquired HCHI assets will be fully integrated with Hydro One's assets to ensure the safe and secure operations and system integrity for both the acquired customers and the neighbouring Hydro One customers. The assets will be maintained and operated by Hydro One in the same fashion and to the same standards as Hydro One's current assets. The acquisition will not adversely affect operational safety or system integrity. For more information, please refer to **Exhibit A, Tab 2, Schedule 1 Section 1.3.**

1.6.4 Please provide details, including any capital expenditure plans, of how quality and reliability of service will be maintained after completion of the proposed transaction. Indicate where service centres will be located and expected response times.

> Hydro One will use its Asset Risk Assessment (**"ARA"**) process to determine capital expenditures required for operating and maintaining the current HCHI service territory to provide the same or better

quality and reliability as customers experience today.

In performing maintenance on the acquired HCHI distribution system, Hydro One's system standards will be used. Hydro One will thereby be able to serve the customers of HCHI with the same level of service Hydro One provides its existing customers by virtue of the existing customer service practices and policies of Hydro One.

Electric utility service to customers currently served by HCHI will remain subject to OEB rules and regulations governing all Ontario distributors.

Reliability will be maintained from the use of existing and required resources and as a result response times are not expected to be affected

1.6.5 Please indicate whether the parties to the proposed transaction intend to undertake a rate harmonization process after the proposed transaction is completed. If yes, please provide a description of the plan.

As industry rates evolve over the next five-plus years, Hydro One expects to file a rate application consistent with the OEB rate-making principles (e.g. fair, practical, clear, rate stability and effective cost recovery of revenue requirement). The rate application at that time may propose: (i) to create new acquired customer rate classes; (ii) to move acquired customers to an appropriate Hydro One rate class existing at that time; or (iii) some other option. Hydro One will assess which of these approaches will be adopted at the time of setting new rates for the current HCHI, considering the bill impact on both legacy and acquired customers. Some considerations in deciding on rate strategies include the number and characteristic of the acquired utilities, customer growth in the acquired utilities and potential development within the electricity regulatory arena in Ontario.

If required, Hydro One will have also maintained the ability to have a separate revenue requirement for HCHI, by separately tracking all costs associated with this business.

Whichever approach is adopted for setting the rates of acquired utilities, any future proposed rate applications will be subject to OEB approval and will satisfy the Board's "Filing Requirements for Electricity Distribution Rate Applications". Until the end of the five-year freeze period, Hydro One proposes to retain separate distribution rate schedules for customers in each of the service areas – i.e. those currently served by Hydro One and those currently served by HCHI. Please see **Exhibit A, Tab 2, Schedule 1, Sections 1.2 and 2.0** for further details on rates.

1.6.6 If the application is for an amalgamation, please provide a proposal for the time of rebasing the consolidated entity in accordance with the five-year limit set by the Board.

The proposed transaction does not contemplate an amalgamation.

For details on Hydro One's rebasing strategy, please see **Exhibit A, Tab 2, Schedule 1, Section 2.0.**

1.6.7 Please identify all incremental costs that the parties to the proposed transaction expect to incur. These may include incremental transaction costs, (i.e., legal), incremental merged costs (i.e., employee severances), and incremental ongoing costs (i.e., purchase and maintenance of new IT systems). Please explain how the new utility plans to finance these costs.

> The transaction will not result in a new utility.
>
> Incremental costs associated with the transaction include costs incurred for due diligence, to negotiate and complete the transaction, costs associated with the integration, and costs to transfer the customers into Hydro One's customer and outage management systems. These costs (estimated to be \$2.5 to \$4 million) will be incurred during the rate-freeze period. They will be offset through productivity gains associated with the transaction, and will not be included in Hydro One's distribution revenue requirement. Therefore these incremental costs will not be funded by ratepayers**.**

1.6.8 Please describe the changes, if any, in distribution or transmission rate levels (as applicable) and the impact on the total bill that may result from the proposed transaction.

> Please see **Exhibit A, Tab 2, Schedule 1 Section 1.2.1** for changes/impacts on the total bill as a result of this transaction. Detailed calculations of these bill impacts can be found in **Exhibit A, Tab 3, Schedule 1, Attachment 14.**

1.6.9 Please provide details of the costs and benefits of the proposed transaction to the customers of the parties to the proposed transaction.

> HCHI's distribution customers will experience no harm from this transaction. There will be no additional costs to the customers of the parties to the proposed transaction. To the contrary, and as stated in **Section 1.6.2**, the customers will have the benefit of a negative rate rider requested in this Application and have their rates frozen at that reduced level for the next five years.
>
> Hydro One's current customers will continue to enjoy the same service they receive now. In the long term, because fixed costs of operations will be spread over a wider customer base, Hydro One customers will see a small price benefit.
>
> This transaction meets the Board's five objectives as set out in Section 1 of the Act as described in **Exhibit A, Tab 2, Schedule 1, Section 1**.

1.7 Economic Efficiency

1.7.1 Please indicate the impact the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity). Details on the impacts of the proposed transaction on economic efficiency and cost effectiveness should include, but are not limited to, impacts on administration support functions such as IT, accounting, and customer service.

Please see **Exhibit A, Tab 2, Schedule 1, Section 1.**

1.8 Financial Viability

1.8.1 Please provide a valuation of any assets or shares that will be transferred in the proposed transaction. Provide details on how this value was determined, including any assumptions made about future rate levels.

HOI and the Corporation of Haldimand County have entered into a Share Purchase Agreement whereby HOI will be purchasing all of the shares of HCUI, which owns all of the shares of HCHI. The Corporation of Haldimand County also retained the services of Norton Rose Fulbright Canada LLP ("Norton Rose Fulbright") to advise and assist in evaluating the offer from HOI resulting in the sale of the shares of HCUI. The Corporation of Haldimand County is satisfied that the price to be received is fair and reasonable.

HOI considered the financial statements, as well as cash flow projections, an assessment of asset condition, one-time costs of integration and potential efficiency gains in assessing the value of the business.

Please refer to **Section 1.6.2** for discussion regarding future rate levels.

1.8.2 If the price paid as part of the proposed transaction is significantly more than the book value of the assets of the selling utility, please provide details as to why this price will not have an adverse affect on the economic viability of the acquiring utility.

The premium paid over the book value on the transaction will not have a material impact on HOI's financial viability. In addition, the premium paid over the net book value of the assets will not be recovered through Hydro One rates.

1.8.3 Please provide details of the financing of the proposed transaction.

HOI will initially finance the proposed transaction through cash or its short-term commercial paper program, which is operational and fully backed by a syndicated bank line of credit maturing June, 2019. Long-term financing will be through its Medium-Term Note program, which is fully operational and valid until October, 2015, and planned to be renewed thereafter.

1.8.4 If the proposed transaction involves a leasing arrangement, please identify separately any assets in the service area that are owned, from those assets that are encumbered by any means, e.g., subject to a lease or debt covenant.

This transaction does not involve a leasing arrangement.

1.8.5 Please outline the capital (debt/equity) structure, on an actual basis, of the parties to the proposed transaction prior to the transaction and on a pro forma basis after completion of the proposed transaction. In order to allow the Board to assess any potential impacts on the utility's financial viability, please include the terms associated with the debt structure of the utility as well as the utility's dividend policy after the completion of the proposed transaction. Please ensure that any debt covenants associated with the debt issue are also disclosed.

The premium paid over the book value on the transaction will not have a material impact on Hydro One's or HOI's financial viability. In alignment with Board practice and as referred to in Board Staff's Discussion Paper on Rate Making Associated with Distributor Consolidation, the premium paid over the net book value of the assets will not be recovered through Hydro One rates.

1.8.6 Please provide details of any potential liabilities associated with the proposed transaction in relation to public health and safety matters or environmental matters. These may be matters that have been identified in the audited financial statements or they may be matters that the parties have become aware of since the release of the most recently audited financial statements. If there are any pre-existing potential liabilities regarding public health and safety matters or environmental matters for any party to the proposed transaction, provide details on how the parties propose to deal with those potential liabilities after the transaction is completed. Specify who will have on-going liability for the pre-existing potential liabilities.

Certain environmental matters were disclosed by the Corporation of Haldimand County as part of the due diligence process and as part of its disclosures under the Agreement. Liability for these matters remains with the Corporation of Haldimand County until the properties subject to the environmental concerns are transferred to Hydro One. Hydro One manages a distribution business throughout the Province with assets similar to those of HCHI and has programs in place to deal with any relevant safety and environmental matters.

1.9 <u>Other Information</u>

1.9.1 If the proposed transaction requires the approval of a parent company, municipal council or any other entity please provide a copy of appropriate resolutions indicating that all such parties have approved the proposed transaction.

A copy of the resolution authorizing the sale of shares to HOI is provided as **Exhibit A, Tab 3, Schedule 1, Attachment 13.**

1.9.2 Please list all suits, actions, investigations, inquiries or proceedings by any government body, or other legal or administrative proceeding, except proceedings before the Board, that have been instituted or threatened against each of the parties to the proposed transaction or any of their respective affiliates.

There are none associated with the parties to this Application related to this transaction.

1.9.3 Regarding net metering thresholds, the Board will, absent exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Please indicate the current net metering thresholds of the utilities involved in the proposed transaction. Please also indicate if there are any special circumstances that may warrant the Board using a different methodology to determine the net metering threshold for the new or remaining utility.

The current net metering thresholds of Hydro One and HCHI are 14,330 kW and 802 kW respectively. There are no special circumstances that warrant the Board using a different methodology to determine the net metering threshold for each utility. Therefore, Hydro One and HCHI submit that individual CDM targets for both Hydro One and HCHI should remain separate.

1.9.4 Please provide the Board with any other information that is relevant to the application. When providing this additional information, please have due regard to the Board's objectives in relation to electricity.

This transaction was completed on a commercial basis between a willing seller and a willing buyer. It is a demonstration of the type of benefits that can be realized from voluntary consolidation; it will deliver cost synergies and economy of scale benefits contemplated by the Ontario Distribution Sector Review Panel and will promote the objectives contained in the OEB's Renewed Regulatory Framework for Electricity Distributors. This transaction eliminates the duplication of effort between Hydro One and HCHI and results in a single electric distribution service provider for all of the regional area, which will ultimately lead to a lower cost of service across the combined service areas and will create downward pressure on electricity distribution rates.

PART II: CERTIFICATION AND ACKNOWLEDGMENT

2.1 Certification and Acknowledgment

I certify that the information contained in this application and in documents provided are true and accurate.

Signature of Key Individual	Print Name of Key Individual	Title/Position
Original Signed by Susan Frank	Susan Frank	Chief Regulatory Officer
	Date July 31, 2014	Company 1908872 Ontario Inc.(HO)

Signature of Key Individual	Print Name of Key Individual	Title/Position
Original Signed By Ken Hewitt	Ken Hewitt	Mayor
	Date July 31, 2014	Company The Corporation of Haldimand County

Signature of Key Individual	Print Name of Key Individual	Title/Position
Original Signed By R. Jane Albert	R. Jane Albert	President and CEO
	Date July 31, 2014	Company Haldimand County Utilities Inc.

(Must be signed by a key individual. A key individual is one that is responsible for executing the following functions for the applicant: matters related to regulatory requirements and conduct, financial matters and technical matters. These key individuals may include the Chief Executive Officer, the Chief Financial Officer, other officers, directors or proprietors.) TOR01: 5157356: v2

Attachment List

Attachment 1: Haldimand County Hydro Inc. Distribution Licence – ED-2003-0011

Attachment 2: Hydro One Networks Inc. Distribution Licence – ED-2003-0043

Attachment 3a: Map of Hydro One Networks Inc. Service Area

Attachment 3b: Checkerboard Map of Distributors in HCHI's Surrounding Area

Attachment 3c: Map of Hydro One Service Area Surrounding HCHI

Attachment 4: Hydro One Inc. Corporate Structure

Attachment 5: Haldimand County Hydro Inc. Corporate Structure

Attachment 6: Share Purchase Agreement

Attachment 7: 2013 Hydro One Inc. Financial Statements

Attachment 8: 2012 Hydro One Inc. Financial Statements

Attachment 9: 2013 Hydro One Networks Inc. Distribution Financial Statements

Attachment 10: 2012 Hydro One Networks Inc. Distribution Financial Statements

Attachment 11: 2013 Haldimand County Utilities Inc. Financial Statements

Attachment 12: 2012 Haldimand County Utilities Inc. Financial Statements

Attachment 13: Resolution

Attachment 14: Bill Impact Analysis

Attachment 15: Proposed Rate Schedule for Existing HCHI

Attachment 16: Haldimand County Hydro Customers By Township

Electricity Distribution Licence

ED-2002-0539

Haldimand County Hydro Inc.

Valid Until

October 20, 2023

Original signed by

____

Jennifer Lea
Counsel, Special Projects
Ontario Energy Board
Date of Issuance: October 21 2003
Date of Amendment: November 12, 2010
Date of Amendment: November 9, 2011

Ontario Energy Board	Commission de l’énergie de l’Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th. Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means Haldimand County Hydro Inc.

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"**OPA**" means the Ontario Power Authority;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Provincial Brand**" means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation"** means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

- a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;
- b) for billing, settlement or market operations purposes;
- c) for law enforcement purposes; or
- d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on October 21 2003 and expire on October 20, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

21 **Conservation and Demand Management**

21.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 2.850 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 13.300 GWh (collectively the “CDM Targets”), over a four-year period beginning January 1, 2011.

21.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee’s service area (“Board-Approved CDM Programs”);

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee’s service area under contract with the OPA (“OPA-Contracted Province-Wide CDM Programs”); or

c) a combination of a) and b).

21.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee’s service area.

21.4 The Licensee shall comply with the rules mandated by the Board’s Conservation and Demand Management Code for Electricity Distributors.

21.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee’s own brand or marks.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The Corporation of Haldimand County as defined in the Town of Haldimand Act, 1999, excluding the consumer located at 2330 Regional Road 3.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

1. The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it.

2. The Licensee is exempt from the requirement to implement time-of-use pricing as of the mandatory date as required under the Standard Supply Service Code for Electricity Distributors for three-phase General Service under 50 kW and Residential customers with eligible time-of-use meters with improper time alignment of the consumption intervals. The mandatory time-of-use pricing date exemption expires on January 31, 2012.

APPENDIX A

MARKET POWER MITIGATION REBATES

1. **Definitions and Interpretations**

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. **Information Given to IESO**

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Ontario

Electricity Distribution Licence

ED-2003-0043

Hydro One Networks Inc.

Valid Until

September 28, 2024

Original signed by

____
David Richmond
Manager, Electricity Facilities and Infrastructure Applications
Ontario Energy Board

Date of Issuance: September 29, 2004
Date of Last Amendment: October 30, 2013

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto ON M4P 1E4

Commission de l'énergie de l'Ontario
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LIST OF AMENDMENTS

Board File No.	Date of Amendment
EB-2005-0286	October 12, 2005
EB-2007-0688	November 26, 2007
EB-2007-0912	February 1, 2008
EB-2007-0916	February 27, 2008
EB-2007-0968	March 20, 2008
EB-2007-0792	April 4, 2008
EB-2007-0933	June 26, 2008
EB-2007-0917	July 25, 2008
EB-2008-0269	October 22, 2008
EB-2009-0148	June 3, 2009
EB-2009-0325	November 24, 2009
EB-2009-0325	December 14, 2009
EB-2010-0172	August 26, 2010
EB-2010-0215	November 12, 2010
EB-2010-0282	January 13, 2011
EB-2010-0229	March 7, 2011
EB-2010-0398	March 29, 2011
EB-2011-0018	April 25, 2011
EB-2011-0067	May 18, 2011
EB-2011-0209	September 12, 2011
EB-2011-0118	October 11, 2011
EB-2011-0321	November 9, 2011
EB-2012-0007	March 8, 2012
EB-2012-0088	May 10, 2012
EB-2012-0204	July 5, 2012
EB-2012-0305	September 27, 2012
EB-2012-0343	November 8, 2012
EB-2012-0384	December 21, 2012
EB-2013-0373	October 30, 2013

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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means Hydro One Networks Inc.

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"**OPA**" means the Ontario Power Authority;

“**Performance Standards**” means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

“**Provincial Brand**” means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

“**Rate Order**” means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

“**regulation**” means a regulation made under the Act or the Electricity Act;

“**Retail Settlement Code**” means the code approved by the Board which, among other things, establishes a distributor’s obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

“**service area**” with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

“**Standard Supply Service Code**” means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

“**wholesaler**” means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the Licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

14.3 The Licensee shall:

a) immediately notify the Board in writing of the notice; and

b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this Licence.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on September 29, 2004 and expire on September 28, 2024. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

21 Conservation and Demand Management

21.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 213.660 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 1,130.210 GWh (collectively the "CDM Targets"), over a four-year period beginning January 1, 2011.

21.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee's service area ("Board-Approved CDM Programs");

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or

c) a combination of a) and b).

21.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.4 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. Municipalities as set out in Appendix B – Tab 1.

2. First Nation Reserves as set out in Appendix B – Tab 2.

3. Unorganized Townships as set out in Appendix B – Tab 3.

4. Municipalities in which a portion of the municipality is served by the Licensee and another portion of the municipality is served by another distributor. as set out in Appendix B – Tab 4.

5. Consumers embedded within another distributor but served by the Licensee as set out in Appendix B – Tab 5.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

1. The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

1. The Licensee is exempt from the provisions of the Standard Supply Service Code for Electricity Distributors requiring time-of-use pricing for RPP consumers with eligible time-of-use meters, as of the mandatory date. This exemption applies only for service to approximately 122,000 of the identified hard to reach customers who, as of October 31, 2012 and as per Decision and Order EB-2012-0384, are outside the reach of the Licensee's smart meter telecommunications infrastructure. This exemption expires December 31, 2014.

2. The Licensee is exempt from the requirement of section 6.2.4.1e(i) of the Distribution System Code with respect to the following 12 generation projects, as per the Board's Decision and Order in EB-2010-0229:

Project ID	Generator Name	Project Name
11,690	Grand Valley Wind Farms Inc.	Grand Valley Wind Farms (Phase 2)
11,700	Invenergy Wind Centre ULC	Conestogo Wind Centre 2
11,720	Conestogo Wind, LP	Conestogo Wind Centre
11,870	International Power Canada, Inc.	Plateau I and II Wind
12,270	Pukwis Wind Partner Inc. & Pukwis Energy Co-op	Pukwis Community Wind Park
12,290	Glead Power Corporation	22.5 MW Ostrander Wind Farm
12,430	Grey Highlands Clean Energy LP	Grey Highlands Clean Energy
12,610	ZEP Wind Farm Ganaraska LP	ZEP Wind Farm Ganaraska
12,750	Clean Breeze Wind Park LP	Clean Breeze Wind Park
12,800	Southbranch Wind Farm Inc.	Southbranch Wind Farm
12,810	WPD Canada Corporation	Sumac Ridge Wind Farm
12,860	WPD Canada Corporation	Fairview Wind Farm

3. As per the Board's Decision and Order in EB-2011-0067, for generation facilities for which the primary energy source is water with a capacity not exceeding 10 megawatts and that are located on provincial Crown or federally-regulated lands and for which the electrical connection is to the distribution system owned by Hydro One Networks Inc. ("Hydro One"), Hydro One shall be exempted from the current connection cost deposit stipulated in s. 6.2.18(a) of the Distribution System Code (the"DSC") and shall, instead, adhere to the following schedule:

   (a) $20,000 per MW of capacity shall be paid by the proponent to Hydro One upon the execution of the Connection Cost Agreement.

   (b) An additional deposit in the amount of 30% of the total estimated cost, as estimated by Hydro One, less the amount received by Hydro One under paragraph (a) above, shall be paid by the proponent to Hydro One no later than 6 months after the proponent notifies Hydro One that it has issued its statement of completion under the earlier of the Waterpower Class Environmental Assessment and the equivalent environmental assessment process under the Canadian Environmental Assessment Act.

   (c) No later than 180 days after Hydro One receives payment of the amount referenced in paragraph (b) above, Hydro One shall provide to the proponent a construction schedule and a more accurate estimate of the project cost, if such estimate is requested and paid for by the proponent. The payment for the estimate shall be drawn from the deposit to the extent possible.

(d) The balance of the total estimated cost, as estimated by Hydro One based upon the best available information, shall be paid by the proponent to Hydro One no later than 30 days after the proponent notifies Hydro One that it has received the last of its necessary construction approval permits under Ontario's Lakes and Rivers Improvement Act or the Dominion Water Power Act.

(e) Hydro One and the proponent shall mutually agree upon an in-service date that is no later than 2 years after Hydro One receives the balance referenced in paragraph (d), above, subject to the following: in cases where a transmission upgrade or new transmission facilities are required, Hydro One and the proponent may agree to an in-service date that is later than two years after Hydro One receives the balance referenced in paragraph (d), above.

(f) The Expansion Deposit, as stipulated by Section 3.2.20 of the DSC, shall be paid to Hydro One at the same time as the payment in paragraph (d).

Notwithstanding the foregoing, if at any time the above-noted payments to Hydro One are insufficient to cover Hydro One's costs as estimated by Hydro One, the proponent shall pay, to Hydro One, additional funding sufficient to meet the shortfall identified by Hydro One, and Hydro One shall be relieved of its obligation to perform such further work until it receives the said additional funding.

4. For the Trout Creek Wind Farm (Hydro One Project #12,780), Hydro One shall be exempted from the current connection cost deposit stipulated in s. 6.2.18(a) of the Distribution System Code (the "DSC") and shall, instead, adhere to the following schedule:

(a) $20,000 per MW of capacity shall be paid by the proponent to Hydro One upon the execution of the Connection Cost Agreement.

(b) An additional deposit in the amount of 30% of the total estimated cost, as estimated by Hydro One, less the amount received by Hydro One under paragraph (a) above, shall be paid by the proponent to Hydro One no later than 4 months after the proponent notifies Hydro One that it has completed the Renewable Energy Approval.

(c) No later than 180 days after Hydro One receives payment of the amount referenced in paragraph (b) above, Hydro One shall provide to the proponent a construction schedule and a more accurate estimate of the project cost, if such estimate is requested and paid for by the proponent. The payment for the estimate shall be drawn from the deposit to the extent possible.

(d) The balance of the total estimated cost, as estimated by Hydro One based upon the best available information, shall be paid by the proponent to Hydro One no later than 30 days after the proponent notifies Hydro One that it is proceeding to construction. If this notification is not given by May 31, 2015, then the proponent's capacity allocation shall be removed.

(e) Hydro One and the proponent shall mutually agree upon an in-service date that is no later than 2 years after Hydro One receives the balance referenced in paragraph (d), above, subject to the following: in cases where a transmission upgrade or new transmission facilities are required, Hydro One and the proponent may agree to an in-service date that is later than two years after Hydro One receives the balance referenced in paragraph (d), above.

(f) The Expansion Deposit, as stipulated by Section 3.2.20 of the DSC shall be paid to Hydro One at the same time as the payment in paragraph (d).

Notwithstanding the foregoing, if at any time the above-noted payments to Hydro One are insufficient to cover Hydro One's costs as estimated by Hydro One, the proponent shall pay, to Hydro One, additional funding sufficient to meet the shortfall identified by Hydro One, and Hydro One shall be relieved of its obligation to perform such further work until it receives the said additional funding.

5. As per the Board's Decision and Order in EB-2012-0343:

(a) The Licensee is exempt from section 6.2.6 of the Distribution System Code for micro-embedded generation projects that are an indirect connection requiring a site assessment. This exemption expires August 3, 2013 or six months after the conclusion of the Board's consultation EB-2012-0246, whichever is earlier. During the period of exemption, for micro-embedded generation projects that are an indirect connection requiring a site assessment, the Licensee shall be required to issue an offer to connect or issue reasons for refusal within 30 days, for at least 90% of applications. If a customer requests a delay with respect to 6.2.6, the additional time will be added to the timeline. Hydro One Networks Inc. shall track its compliance with this provision. For all projects other than micro-embedded generation projects that are an indirect connection requiring a site assessment, the application of section 6.2.6 of the Distribution System Code shall remain unchanged.

(b) The Licensee is exempt from the provisions of 6.2.7 of the Distribution System Code for micro-embedded generation applications. This exemption expires August 3, 2013 or six months after the conclusion of the Board's consultation EB-2012-0246, whichever is earlier. During the period of exemption, the Licensee shall comply with the provisions of sections 7.2.1 and 7.2.3 of the Distribution System Code.

SCHEDULE 4 LIST OF RRR EXEMPTIONS

The Licensee is exempt from the following sections of the Electricity Reporting and Record Keeping Requirements:

1. Section 2.1.5.5 (b)

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.
Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.
If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

APPENDIX B

TAB 1 MUNICIPALITIES

Name of Municipality:	Township of Addington Highlands
Formerly Known as:	Township of Denbign, Abinger and Ashby, Township of Anglesea and Effingham, Kaladar, as at December 31. 1999.
Name of Municipality:	Township of Adelaide Metcalfe
Formerly Known As:	Township of Adelaide, Township of Metcalfe, as at December 31, 2000.
Name of Municipality:	Township of Adjala-Tosorontio
Formerly Known As:	Portions of the Township of Adjala, Township of Tosorontio, Township of Sunnidale, as at December 31, 1993.
Name of Municipality:	Township of Admaston/Bromley
Formerly Known As:	Township of Admaston, Township of Bromley, as at December 31, 1999.
Name of Municipality:	Township of Alberton as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Algonquin Highlands, (Formerly known as Township of Sherborne, Stanhope, McClintock, Livingstone, Lawrence and Nightingale)
Formerly Known As:	Township of Sherborne et al,Township of Stanhope, as at December 31, 2000.
Name of Municipality:	Township of Alnwick/Haldimand
Formerly Known As:	Township of Alnwick, Township of Haldimand, as at December 31, 2000.
Name of Municipality:	Township of Amaranth as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality: Township of The Archipelago as at March 31, 1999.
Formerly Known As: Conger, Cowper, Harrison, Henvey, Wallbridge plus geographic/unorganized townships and unsurveyed areas

Name of Municipality: Township of Armour as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Armstrong as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Arnprior as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Arran-Elderslie
Formerly Known As: Township of Arran, Township of Elderslie, Town of Chesley, Village of Tara, Village of Paisley, as at December 31, 1998.

Name of Municipality: Township of Ashfield-Colborne-Wawanosh
Formerly Known As: Township of Ashfield, Township of West Wananosh, Township of Colborne, as at December 31, 2000.

Name of Municipality: Township of Assiginack as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Athens
Formerly Known As: Township of Rear of Young and Escott, Village of Athens, as at December 31, 2000.

Name of Municipality: Township of Augusta as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Baldwin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Bancroft
Formerly Known As: Town of Bancroft, Township of Dungannon, as at December 31, 1998.

Name of Municipality: Township of Barrie Island as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Bayham
Formerly Known As: Township of Baymen, Village of Port Burwell, Village of Vienna, as at December 31, 1997.

Name of Municipality: Township of Beckwith as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Billings as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Black River-Matheson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Blind River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Bonfield as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Bonnechere Valley
Formerly Known As: Village of Eganville, Township of Grattan, Township of Sebastopol, Township of South Algona, as at December 31, 2000.

Name of Municipality: Township of Brethour as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Brighton
Formerly Known As: Town of Brighton, Township of Brighton, as at December 31, 2001.

Name of Municipality: City of Brockville as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Brudenell, Lyndoch and Raglan
Formerly Known As: Township of Brudenell and Lyndoch, Township of Raglan, as at December 31, 1998.

Name of Municipality: Township of Burpee and Mills
Formerly Known As: Township of Burpee, Unorganized Twp of Mills, as at December 31, 1997.

Name of Municipality: Town of Caledon
Formerly Known As: Township of Albion, Township of Caledon, Village of Bolton, Village of Caledon East, Township of Chinguacousy (part), as at December 31, 1973.

Name of Municipality: Township of Calvin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Carleton Place as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Carling as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Carlow/Mayo
Formerly Known As: Township of Carlow, Township of Mayo, as at December 31, 2000.

Name of Municipality: Township of Casey as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Cavan-Millbrook-North Monoghan
Formerly Known As: Township of Cavan, Township of North Monaghan,
Village of Millbrook, as at December 31, 1997.

Name of Municipality: Township of Central Frontenac
Formerly Known As: Township of Hinchinbrooke, Township of Kennebec, Township of Olden, Township of Oso, as at December 31, 1997.

Name of Municipality: Township of Central Manitoulin
Formerly Known As: Twp. Of Carnarvon, Unorganized Twp of Sandfield, as at April 30, 1997.

Name of Municipality: Municipality of Centre Hastings
Formerly Known As: Village of Madoc, Township of Huntingdon, as at December 31, 1997.

Name of Municipality: Township of Chamberlain as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Champlain
Formerly Known As: Village of L'Orignal, Township of West Hawkesbury, Township of Longueuil, Town of Vankleek Hill, as at December 31, 1997.

Name of Municipality: Township of Chapple as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Charlton and Dack
Formerly Known As: Town of Charlton, Township of Dack, as at December 31, 2002.

Name of Municipality: Township of Chatsworth
Formerly Known As: Village of Chatsworth, Township of Holland, Township of Sullivan, as at December 31, 1999.

Name of Municipality: Township of Chisolm as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Clarence-Rockland
Formerly Known As: Town of Rockland, Township of Clarence, as at December 31, 1997.

Name of Municipality: Town of Cobalt as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Cockburn Island as at March 31, 1999
Formerly Known As: Same

Name of Municipality: Township of Coleman as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Conmee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Dawn-Euphemia
Formerly Known As: Township of Dawn, Township of Euphemia, as at December 31, 1997.

Name of Municipality: Township of Dawson
Formerly Known As: Township of Atwood, Township of Blue, Township of Worthington, Township of Dilke, as at December 31, 1996.

Name of Municipality: Town of Deep River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Deseronto as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Dorion as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Douro-Dummer
Formerly Known As: Township of Douro, Township of Dummer, as at December 31, 1997.

Name of Municipality: Township of Drummond/North Elmsley
Formerly Known As: Township of Drummond, Township of North Elmsley, as at December 31, 1997.

Name of Municipality: City of Dryden
Formerly Known As: Town of Dryden, Township of Barclay

Name of Municipality: Township of Dysart et al as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Ear Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of East Ferris as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of East Garafraxa as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of East Hawkesbury as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Elizabethtown-Kitley
Formerly Known As: Township of Kitley, Township of Elizabethtown as at December 31, 2000.

Name of Municipality: City of Elliott Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Emo, as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Englehart as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Enniskillen as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Erin
Formerly Known As: Township of Erin, Village of Erin, as at December 31, 1997.

Name of Municipality: Township of Evantural as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Faraday as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Fauquier-Strickland as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of French River
Formerly Known As: Township of Cosby, Township of Mason, Township of Martland, geographic/unorganized townships of Delamere, Hoskin and Scollard in whole and Bigwood, Cherriman and Haddo in part, as at December 31, 1998.

Name of Municipality: Township of Front of Yonge as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Frontenac Islands
Formerly Known As: Township of Howe Island, Township of Wolfe Island, as at December 31, 1997.

Name of Municipality: Township of Galway-Cavendish and Harvey
Formerly Known As: Township of Galway and Cavandish, Township of Harvey, as at December 31, 1997.

Name of Municipality: Township of Gauthier as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Georgian Bay as at March 31, 1999.
Formerly Known As: Township of Freeman, Township of Gibson, Township of Baxter.

Name of Municipality: Township of Georgian Bluffs
Formerly Known As: Township of Derby, Township of Keppel, Township of Sarawak, as at December 31, 2000.

Name of Municipality: Town of Georgina as at March 31, 1999.
Formerly Known As: Township of North Gwillimbury, Township of Georgina.

Name of Municipality: Township of Gillies as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Gordon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Gore Bay as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Greater Madawaska
Formerly Known As: Township of Bagot, Blythfield and Brougham, Township of Griffith, and Matawatchan, (Jan 1998: Township of Bagot and Blythfield, Township of Brougham amalgamated into Township of Bagot, Blythfield and Brougham), as at December 31, 2000.

Name of Municipality: Town of Greater Napanee
Formerly Known As: Township of Adolphustown, Township of North Fredericksburgh, Township of South Fredericksburgh, Township of Richmond, Town of Napanee, as at December 31, 1997.

Name of Municipality: Municipality of Greenstone
Formerly Known As: Town of Geraldton, Town of Longlac, Township of Beardmore, Township of Nakina, as at December 31, 2000.

Name of Municipality: Municipality of Grey Highlands
Formerly Known As: Township of Artemesia, Township of Euphrasia
Village of Markdale, Township of Osprey, as at December 31, 2000.

Name of Municipality: Township of Hamilton as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Harley as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Harris as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Hastings Highlands
Formerly Known As: Township of Bangor, Wicklow and McClure, Township of Herschel, Township of Monteagle, as at December 31, 2000.

Name of Municipality: Township of Havelock-Belmont-Methuen
Formerly Known As: Township of Belmont and Methuen, Village of Havelock, as at December 31, 1997.

Name of Municipality: Township of Head, Clara and Maria, as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Highland East
Formerly Known As: Township of Bicroft, Township Cardiff, Township of Glamorgan, Township of Monmouth, as at December 31, 2000.

Name of Municipality: Township of Hilliard as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Hornpayne as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Horton as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: The Township of Howick as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Hudson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality:	Township of Ignace as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of James as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Joly as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	The City of Kawartha Lakes
Formerly Known As:	County of Victoria, Town of Lindsay, Municipality of Bobcaygeon/ Verulam, Village of Fenelon Falls, Village of Omemee, Village of Sturgeon Point, Village of Woodville, Township of Bexley, Township of Carden/Dalton, Township of Eldon, Township of Emily, Township of Fenelon, Township of Laxton, Digby and Longford, Township Manvers, Township of Mariposa, Township of Ops, Township of Somerville, (Jan 2000: Township of Carden , Township of Dalton amalgamated into Township of Carden/Dalton), (Jan 2000; Village of Bobcaygeon/Township of Verulam amalgamated into the Municipality of Bobcaygeon/Verulam), as at December 31, 2000.
Name of Municipality:	Town of Kearney as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Kerns as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Municipality of Killarney
Formerly Known As:	Townships of Rutherford and George Island and the geographic/unorganized townships of, Allen, Atlee, Goschen, Hansen, Killarney, Kilpatrick, Sale, Struthers, Travers, and portions of the geographic/unorganized townships of Bigwood, Carlyle, Humboldt, Mowat, and unsurveyed territory and islands, as at December 31, 1998.

Name of Municipality: Town of Kirkland Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of La Vallee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Lake of Bays as at March 31, 1999.
Formerly Known As: Township of McLean, Township of Ridout, Township of Franklin, Township of Sinclair, Township of Finlayson.

Name of Municipality: Township of Lake of the Woods
Formerly Known As: Township of McCrosson and Tovell, Township of of Morson, unorganized islands in Kenora District and Rainy River District, as at December 31, 1998.

Name of Municipality: Municipality of Lambton Shores
Formerly Known As: Village of Arkona, Town of Bosanquet, Town of Forest, Village of Grand Bend, Village of Thedford, as at December 31, 2000.

Name of Municipality: Township of Lanark Highlands
Formerly Known As: Township of Darling, Township of North West Lanark, (May 1997: Lavant, Dalhousie and North Sherbrook Township/Township Lanark/Village Lanark amalgamated into Township of North West Lanark), as at June 30, 1996.

Name of Municipality: Township of Larder Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Latchford as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Laurentian Hills
Formerly Known As: Township of Rolph, Township of Wylie and McKay, Village of Chalk River, as at December 31, 1999.

Name of Municipality: Township of Laurentian Valley
Formerly Known As: Township of Stafford and Pembroke, Township of Alice and Fraser, as at December 31, 1999.

Name of Municipality: Township of Limerick as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Loyalist
Formerly Known As: Township of Amherst Island, Township of Ernestown, Village of Bath, as at December 31, 1997.

Name of Municipality: Township of Lucan Biddulph
Formerly Known As: Village of Lucan, Township of Biddulph, Police Village of Granton, as at December 31, 1998.

Name of Municipality: Township of Machar as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Machin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Madawaska Valley
Formerly Known As: Village of Barry's Bay, Township of Radcliffe, Township of Sherwood, Jones and Burns, as at December 31, 2000.
Name of Municipality: Township of Madoc as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Malahide
Formerly Known As: Township of Malahide, Township of Dorchester, Village of Springfield, as at December 31, 1997.

Name of Municipality: Township of Manitouwadge as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mapleton
Formerly Known As: Township of Mapleton, Township of Maryborough, (Jan 1998-Village of Drayton, Township of Peel amalgamated into the Township of Mapleton), as at December 31, 1998.

Name of Municipality: Town of Marathon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Markstay-Warren
Formerly Known As: Township of Hagar, Township of Ratter and Dunnet, geographic/unorganized township of Awrey and portions of the geographic/unorganized townships of Hawley, Henry, Loughrin, Street, as at December 31, 1998.

Name of Municipality: Municipality of Marmora and Lake
Formerly Known As: Township of Marmora and Lake, Village of Marmora, (Jan 1998: Village of Deloro, Township of Marmora and Lake amalgamated into the Township of Marmora and Lake, as at December 31, 1997.

Name of Municipality: Township of Matachewan as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Mattawa as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mattawan as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mattice-Val Cote as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of McDougall
Formerly Known As: Township of McDougall, geographic/unorganized township of Ferguson, as at December 31, 1999.

Name of Municipality: Township of McGarry as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of McKellar as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of McMurrich/Monteith
Formerly Known As: Township of McMurrich, geographic/unorganized township of Monteith (eastern portion), as at December 31, 1997.

Name of Municipality: Township of McNab/Braeside
Formerly Known As: Township of McNab, Village Braeside, as at December 31, 1997

Name of Municipality: Municipality of Meaford (formerly known as Town of Georgian Highlands)
Formerly Known As: Township of St. Vincent, Township of Sydenham, Town of Meaford, as at December 31, 2000.

Name of Municipality: Township of Melancthon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Village of Merrickville-Wolford
Formerly Known As: Township of Wolford, Village of Merrickville, as at December 31, 1997.

Name of Municipality: Township of Middlesex Centre
Formerly Known As: Township of Lobo, Township of London, Township of Delaware, Police Village of Delaware, as at December 31, 1998.

Name of Municipality: Township of Minden Hills
Formerly Known As: Township of Anson, Hindon and Minden, Township of Lutterworth, Township of Snowdon, as at December 31, 2000.

Name of Municipality : Town of Mono as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Montague as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Moonbeam as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Moosonee as at March 31, 1999.
Formerly Known As: Moosonee Development Board

Name of Municipality: Township of Morley
Formerly Known As: Township of Morley, geographic/unorganized townships Twp's of Dewart and Sifton, as at December 31, 2003.

Name of Municipality: Municipality of Morris-Turnberry
Formerly Known As: Township of Morris, Township of Turnberry, as at December 31, 2000.

Name of Municipality: Township of Mulmar as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Muskoka Lakes as at March 31, 1999.
Formerly Known As: Township of Cardwell, Township of Watt, Township of Medora, Township of Monck, Township of Wood.

Name of Municipality: Township of Nairn and Hyman
Formerly Known As: Township of Nairn, Unorganized Township of Hyman, as at December 31, 1997.

Name of Municipality: The Nation Municipality
Formerly Known As: Township of Cambridge, Township of South Plantagenet, Village of St. Isidore, Township of Caledonia, as December 31, 1997.

Name of Municipality: Municipality of Neebing as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Temiskaming Shores
Formerly Known As: **T**own of New Liskeard, Town of Haileybury, Township of Dymond, as at December 31, 2003.

Name of Municipality: Township of Nipigon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Nipissing as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Algona-Wilberforce
Formerly Known As: Township of North Algona, Township of Wilberforce, as at December 31, 1998.

Name of Municipality: Municipality of Northern Bruce Peninsula
Formerly Known As: Township of St. Edmunds, Township of Lindsay, Township of Eastnor, Village of Lion's Head, as at December 31, 1998.

Name of Municipality: Township of North Dundas
Formerly Known As: Township of Mountain, Township of Winchester, Village of Chesterville, Village of Winchester, as at December 31, 1997.

Name of Municipality: Township of North Frontenac
Formerly Known As: Township of Barrie, Township of Clarendon,
Township of Miller, Township of Palmerston, Township of North Canonto,
Township of South Canonto, as at December 31, 1997.

Name of Municipality: Township of North Glengarry
Formerly Known As: Township of Kenyon, Township of Lochiel, Town of Alexandria, Village of Maxville, Police Village of Apple Hill, as at December 31, 1997.

Name of Municipality: Township of North Grenville
Formerly Known As: Township of Oxford-on-Rideau, Town of Kemptville, Township of South Gower, as at December 31, 1997.

Name of Municipality: Township of North Himsworth as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Kawartha
Formerly Known As: Township of Burleigh and Anstruther, Township of Chandos, as at December 31, 1997.

Name of Municipality: Town of North Perth
Formerly Known As: Township of Wallace, Township of Elma, Town of Listowel, as at December 31, 1997.

Name of Municipality: Township of The North Shore as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Stormont
Formerly Known As: Township of Finch, Township of Roxborough, Village of Finch, Police Village of Avonmore (in the Township of Roxborough), as at December 31, 1997.

Name of Municipality: Town of Northeastern Manitoulin and the Islands
Formerly Known As: Township of Howland, Town of Little Current, all islands not part of other municipalities on Manitoulin Island, as at December 31, 1997.

Name of Municipality: Township of O'Conner as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Oliver Paipoonge
Formerly Known As: Township of Oliver, Township of Paipoonge, as at December 31, 1997.

Name of Municipality: Township of Opasatika as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Oro-Medonte
Formerly Known As: Portions of the Township of Medonte, Township of Oro, Township of Orillia, Township of Tay, Township of Flos, Township of Vespra, as at December 31, 1993.

Name of Municipality: Township of Otonabee-South Monaghan
Formerly Known As: Township of Otonabee, Township of South Monaghan, as at December 1, 1999.

Name of Municipality: City of Owen Sound as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Papineau-Cameron as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Perry as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Pelee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: The Township of Perth South
Formerly Known As: Township of Downie, Township of Blanshard, as at December 31, 1997.

Name of Municipality: Town of Perth as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Petawawa
Formerly Known As: Village of Petawawa, Township of Petawawa, as at June 30, 1996.

Name of Municipality: Township of Pickle Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Plympton-Wyoming
Formerly Known As: Township of Plympton, Village of Wyoming, as at December 31, 2000.

Name of Municipality: Municipality of Powassan
Formerly Known As: Town of Powassan, Township of Himsworth South, Town of Trout Creek, as at December 31, 2000.

Name of Municipality: County of Prince Edward
Formerly Known As: County of Prince Edward, Town of Picton, Village of Bloomfield, Village of Wellington, Township of Ameliasburgh, Township of Athol, Township of Hallowell, Township of Hillier, Township of North Marysburgh, Township of South Marysburgh, Township of Sophiasburgh, as at December 31, 1997.

Name of Municipality: City of Quinte West
Formerly Known As: City of Trenton, Village of Frankford, Township of Sidney, Township of Murray, as at December 31, 1997.

Name of Municipality: Town of Rainy River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Ramara
Formerly Known As: Township of Mara, Township of Rama , as at December 31, 1993.
Name of Municipality: Township of Red Rock as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Rideau Lakes
Formerly Known As: Village of Newboro, Township of Bastard and South Burgess, Township of North Crosby, Township of South Crosby, Township of South Elmsley, as at December 31, 1997.

Name of Municipality: Township of Ryerson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Schreiber as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Seguin
Formerly Known As: Township of Humphrey, Township of Foley, Township of Christie, geographic/unorganized Township of Monteith (western portion), Village of Rosseau, as at December 31, 1997.

Name of Municipality: Township of Severn
Formerly Known As: Portions of Village of Coldwater, Township of Matchedash, Township of Medonte, Township of Orillia, Township of Tay, as at December 31, 1993.

Name of Municipality: Township of Shedden as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Shelburne as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Shuniah as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Sioux Narrows-Nestor Falls
Formerly Known As: Township of Sioux Narrows, all of the geographic/unorganized townships of Code, Devonshire, Godson, Manross, MacQuarrie, Phillips, Tweedsmuir, and Work, portions of the geographic/unorganized townships of LeMay, McKeekin in Kenora District, and the geographic/unorganized townships of Claxton, Croome, and Mathieu in the Rainy River District, as at December 31, 2000.

Name of Municipality: Separated Town of Smiths Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Smooth Rock Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of South Algonquin
Formerly Known As: Township of Airy and geographic/unincorporated townships of Dickens, Lyell, Murchison and Sabine, as at May 31, 1997.

Name of Municipality: Town of South Bruce Peninsula
Formerly Known As: Township of Albemarle, Township of Amabel, Town of Wiarton, Village of Hepworth, as at December 31, 1998.

Name of Municipality: Township of South Frontenac
Formerly Known As: Township of Bedford, Township of Loughborough, Township of Portland, Township of Storrington, as at December 31, 1997.

Name of Municipality: Village of South River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Southwest Middlesex
Formerly Known As: Township of Ekfrid, Township of Mosa, Village of Glencoe, Village of Wardsville, as at December 31, 2000.

Name of Municipality: Township of Southwold as at March 31, 1999.
Formerly Known As: Same
Name of Municipality: Township of Springwater
Formerly Known As: Portions of the former Village of Elmvale, Township of Flos, Township of Medonte, Township of Vespra, Town of Wasaga Beach, as at December 31, 1993.

Name of Municipality: Municipality of St. Charles
Formerly Known As: Township of Casimir, Jennings & Appleby and the geographic/unorganized townships of Cherriman and Haddo, as at December 31, 1998.

Name of Municipality: Township of St. Clair
Formerly Known As: Township of Sombra, Township of Moore, as at December 31, 2000.

Name of Municipality: Township of Stirling-Rawdon
Formerly Known As: Village of Stirling, Township of Rawdon, as at December 31, 1997.

Name of Municipality: Township of Stone Mills
Formerly Known As: Township of Camden East, Township of Sheffield, Village of Newburgh, as at December 31, 1997.

Name of Municipality: Township of Strong as at March 31, 1996.
Formerly Known As: Same

Name of Municipality: Township of Tay Valley
Formerly Known As: Township of South Sherbrooke, Township of Bathurst, Township of North Burgess, as at December 31, 1997.

Name of Municipality: Township of Tehkummah as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Temagami as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Terrace Bay as at March 31, 1999
Formerly Known As: Same
Name of Municipality: Municipality of Thames Centre
Formerly Known As: Township of North Dorchester, Township of West Nissouri, Village of Dorchester, Police Village of Thorndale, as at December 31, 2000.

Name of Municipality: Town of Thessalon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Village of Thornloe as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Thorold as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Timmins as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Tiny as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Trent Hills
Formerly Known As: Municipality of Campbellford/Seymour, Township of Percy, Village of Hastings, Police Village of Warkworth (Jan 1998-Town of Campbellford, Township of

Seymour amalgamated into the Municipality of Campbellford/Seymour), as at December 31, 2000.

Name of Municipality: Township of Tudor and Cashel as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Tweed
Formerly Known As: Village of Tweed, Township of Hungerford, Township of Elzevir and Gromsthorpe, as at December 31, 1997.

Name of Municipality: Township of Tyendinaga as at March 31, 1999.
Formerly Known As: Same
Name of Municipality: Township of Val Rita-Harty as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Wainfleet as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of West Elgin
Formerly Known As: Township of Aldborough, Village of West Lorne, Police Village of Rodney, as at December 31, 1997.

Name of Municipality: Town of Whitchurch-Stouffville as at March 31, 1999.
Formerly Known As: Village of Stouffville and portions of the Township of Whitchurch and the Township of Markham.

Name of Municipality: Township of White River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Whitestone
Formerly Known As: Township Hagerman, and the geographic/unorganized townships of Ferrie, McKenzie, East Burpee, and a portion of the Township of Magnetawan, as at December 31, 1999.

Name of Municipality: Township of Wollaston as at March 31, 1999.

Formerly Known As: Same

APPENDIX B

TAB 2 FIRST NATION RESERVES

Reserve Name: Abitibi I.R. No. 70
Band Name: Wahgoshig First Nation

Reserve Name: Alderville I.R No. 37
Band Name: Alderville First Nation

Reserve Name: Aroland Indian Settlement
Band Name: Aroland

Reserve Name: Big Grassy River I.R. No. 35G
Band Name: Big Grassy First Nation

Reserve Name: Big Island Mainland 93
Band Name: Anishnaabeg of Naongashiing

Reserve Name: Cape Croker Island I.R. No. 27, Neyaashiinigmiing Reserve
Band Name: Chippewas of Nawash First Nation

Reserve Name: Chippewas of the Thames
Band Name: Chippewas of the Thames First Nation

Reserve Name: Chapleau I.R. No. 74A
Band Name: Chapleau Ojibway First Nation

Reserve Name: Christian Island I.R. No.30
Band Name: Beausoleil First Nation

Reserve Name: Cockburn Island 19, 19A
Band Name: Zhiibaahaasing First Nation

Reserve Name: Constance Lake I.R. 92
Band Name: Constance Lake First Nations

Reserve Name: Couchiching I.R. No. 16A
Band Name: Couchiching First Nation

Reserve Name: Curve Lake I.R. No. 35
Band Name: Curve Lake First Nation

Reserve Name: Dalles I.R. No. 38C
Band Name: Ochiichagwe'babigo'ining First Nation

Reserve Name: Duck Lake R.R. No. 76B
Band Name: Brunswick House First Nation

Reserve Name: Dokis I.R. No. 9
Band Name: Dokis First Nation

Reserve Name: Eagle Lake I.R. No. 27
Band Name: Eagle Lake First Nation

Reserve Name: English River I.R. No.21
Band Name: Grassy Narrows First Nation

Reserve Name: Factory Island I.R. No. 1
Band Name: Moose Factory First Nation

Reserve Name: Georgina Island I.R. No. 33
Band Name: Chippewas of Georgina Island First Nation

Reserve Name: Gibson I.R. No. 31 Wahta mohawk
Band Name: Mohawks of Gibson

Reserve Name: Golden Lake No. 39
Band Name: Algonquins Golden Lake First Nation

Reserve Name: Henvey Inlet I.R. No. 2 French River I.R. 13
Band Name: Henvey Inlet First Nation

Reserve Name: Hiawatha I.R. No.36
Band Name: Ojibways of Hiawatha First Nation

Reserve Name: Islington I.R No. 29
Band Name: Wabasemoong Independent Nations

Reserve Name: Kenora I.R. No. 38B
Band Name: Wauzhushk Onigum Nation

Reserve Name: Kettle Point I.R. No. 44
Band Name: Chippewas of Kettle and Stony Point First Nation

Reserve Name: Lac des Milles Lacs I.R. 22A1, Seine River I.R. 22A2
Band Name: Lac des Milles Lacs

Reserve Name: Lac Suel I.R. No. 28
Band Name: Lac Suel Nation

Reserve Name: Lake Helen I.R. No. 53A
Band Name: Red Rock Band

Reserve Name: Long Lake I.R. No. 77
Band Name: Ginoogaming First Nation

Reserve Name: Long Lake I.R. No. 58
Band Name: Long Lake No. 58 First Nation

Reserve Name: Magnetewan I.R No. 1
Band Name: Magnetewan First Nation

Reserve Name: Manitou Rapids I.R. No. 11
Band Name: Rainy River First Nation

Reserve Name: Matachewan I.R 72
Band Name: Matachewan First Nation

Reserve Name: Mattagami I.R No.71
Band Name: Mattagami First Nation

Reserve Name: Mississagi River I.R No.8
Band Name: Mississauga First Nation

Reserve Name: Mobert I.R No. 82
Band Name: Pic Mobert First Nation

Reserve Name: Moose Point I.R No. 79
Band Name: Moose Deer Point First Nation

Reserve Name: Moravian I.R. No. 47
Band Name: Delaware First Nation

Reserve Name: Muncey Delaware Nation No. 1
Band Name: Munsee-Delaware First Nation

Reserve Name: Neguaguon Lake I.R No. 25d
Band Name: Lac La Croix First Nation

Reserve Name: New Credit I.R 40A
Band Name: Mississaugas of the New Credit First Nation

Reserve Name: New Post 69, 69a
Band Name: New Post First Nation

Reserve Name: Nipissing I.R No. 10
Band Name: Nipissing First Nation

Reserve Name: Northwest Angle I.R No. 33B and Whitefish Bay I.R. No. 33a
Band Name: Northwest Angle No. 33 First Nation

Reserve Name: Oneida I.R No. 41
Band Name: ONA YO TE'A:KA

Reserve Name: Osnaburgh I.R No. 63A, 63B
Band Name: Osnaburgh First Nation

Reserve Name: Parry Island I.R No. 16
Band Name: Wasauksing First Nation

Reserve Name: Pays Plat I.R. No. 51
Band Name: Pays Plat First Nation

Reserve Name: Pic River I..R. No. 50
Band Name: Ojibways of Pic River No. 50 First Nation

Reserve Name: Rainy Lake I.R No. 17A, 17B
Band Name: Naicatchewenin First Nation

Reserve Name: Rainy Lake I.R. 26A
Band Name: ` Nicickousemenecaning First Nation

Reserve Name: Rainy Lake I.R. No. 18c
Band Name: Stanjikoming First Nation

Reserve Name: Rama I.R. No. 32
Band Name: Chippewas of Mnjikaning First Nation
Reserve Name: Rat Portage I.R No. 38A
Band Name: Washagamis Bay First Nation

Reserve Name: Rocky Bay I.R. No. 1
Band Name: Rocky Bay First Nation

Reserve Name: Sabaskong Bay 32c, Whitefish Bay 32a, Yellow Girl Bay 32b
Band Name: Naotkamegwanning Anishnabe First Nation

Reserve Name: Sabaskong Bay I.R 35D
Band Name: Ojibways of Onegaming First Nation

Reserve Name: Sarnia I.R.No.45
Band Name: Chippewas of Sarnia

Reserve Name: Saug-A-Gaw-Sing I.R. No. 1
Band Name: Big Island First Nation

Reserve Name: Saugeen I.R. No. 29
Band Name: Chippewas of Saugeen First Nation

Reserve Name: Savant Lake Indian Settlement
Band Name: Saugeen Nation

Reserve Name: Scugog I.R No. 34
Band Name: Mississauga of Scugog First Nation

Reserve Name: Seine River I.R. No. 23A, 23B, Sturgeon Falls No. 23
Band Name: Seine River First Nation

Reserve Name: Serpent River I.R. No. 7
Band Name: Serpent River First Nation

Reserve Name: Shawanaga I.R. No. 17
Band Name: Shawanaga First Nation

Reserve Name: Sheguiandah I.R. No. 24
Band Name: Sheguiandah First Nation

Reserve Name: Sheshegwaning I.R. No. 20
Band Name: Sheshegwaning First Nation

Reserve Name: Shoal Lake I.R. No 39A
Band Name: Shoal Lake No. 39 First Nation

Reserve Name: Shoal Lake I.R. No 40
Band Name: Shoal Lake No. 40 First Nation

Reserve Name: Six Nations I.R. No. 40
Band Name: Six Nations of the Grand River Territory

Reserve Name: Slate Falls Indian Settlement
Band Name: Slate Falls Nation

Reserve Name: Spanish River I.R. No. 5
Band Name: Sagamok Anishnawbek

Reserve Name: Sucker Creek I.R NO. 23
Band Name: Sucker Creek First Nation

Reserve Name: Thessalon I.R. No. 12
Band Name: Thessalon First Nation

Reserve Name: Tyendinaga Mohawk Territory
Band Name: Mohawks of the Bay of Quinte

Reserve Name: Wabauskang 21
Band Name: Wabauskang First Nation

Reserve Name: Wabigoon Lake I.R No. 27
Band Name: Wabigoon Lake Ojibway Nation

Reserve Name: Wahnapitae 11
Band Name: Wahnapitae First Nation

Reserve Name:	Walpole Island I.R. No.46
Band Name:	Walpole Island First Nation
Reserve Name:	West Bay I.R. No. 22
Band Name:	West Bay First Nation
Reserve Name:	Whitefish Bay I.R No. 32A
Band Name:	Whitefish Bay First Nation
Reserve Name:	Whitefish Bay I.R No. 34A and Lake of the Woods I.R No. 37
Band Name:	Northwest Angle No. 37 First Nation
Reserve Name:	Whitefish Lake I.R. No. 6
Band Name:	Whitefish Lake First Nation
Reserve Name:	Whitefish River I.R. No. 4
Band Name:	Whitefish River First Nation
Reserve Name:	Wikewemikong I.R. No. 26
Band Name:	Wikwemikong Unceded First Nation

APPENDIX B

TAB 3 UNORGANIZED TOWNSHIPS

Networks provides service to numerous Unorganized geographic townships. These townships are not incorporated as municipalities.

APPENDIX B

TAB 4 MUNICIPALITIES IN WHICH A PORTION OF THE MUNICIPALITY IS SERVED BY THE LICENSEE AND ANOTHER PORTION OF THE MUNICIPALITY IS SERVED BY ANOTHER DISTRIBUTOR

Name of Municipality:	**Township of Alfred and Plantagenet**
Formerly Known As:	Township of Alfred, Village of Alfred, Township of North Plantagenet, Village of Plantagenet, as at December 31, 1996.
Area Not Served By Networks:	The area served by Hydro 2000 Inc. described as the former Villages of Alfred and Plantagenet as more particularly set out in Licence No. ED-2002-0542.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Amherstburg**
Formerly Known As:	Town of Amherstburg, Township of Anderdon, Township of Malden, as at December 31, 1997.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Amherstburg as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	Two industrial (former Direct Class) customers located at 381 Front Road North, Amherstburg ON, and 99 Thomas Road, Amherstburg ON

Name of Municipality:	**Township of Asphodel-Norwood**
Formerly Known As:	Township of Asphodel, Village of Norwood, as at December 31, 1997.
Area Not Served By Networks:	The area served by Peterborough Distribution Inc. described as the former Village of Norwood as more particularly set out in Licence No. ED-2002-0504.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Atikokan**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Atikokan Hydro Inc. as set out in Licence No. ED-2003-0001.
Networks assets within area not served by Networks:	No
Customer(s) within area not Served by Networks:	No

Name of Municipality:	**Town of Aylmer as at January 1, 1998.**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the Town of Aylmer as more particularly set out in Licence No. ED-2002-0156.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Belleville**
Formerly Known As:	City of Belleville, Township of Thurlow, City of Quinte West, as at December 31, 1997.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former City of Belleville as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township Blanford-Blenheim**
Formerly Known As:	Township Blanford-Blenheim as at March 31, 1999.
Area Not Served By Networks:	The area served by Cambridge and North Dumfries Hydro Inc. as particularly set out in Licence No. ED-2002-0574. The area served by Kitchener-Wilmot Hydro Inc. as particularly set out in Licence No. ED-2002-0573.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of the Blue Mountains**
Formerly Known As:	Town of Thornbury, Township of Collingwood, as at December 31**,** 1997.
Area Not Served By Networks:	The area served by COLLUS Power Corp. described as the former Town of Thornbury as more particularly set out in Licence No. ED-2002-0518.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Bluewater**
Formerly Known As:	Township of Hay, Township of Stanley, Village of Bayfield, Village of Hensall, Village of Zurich, as at December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Village of Hensall, and the former Village of Zurich as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Bracebridge**
Formerly Known As:	Townships of Macaulay, Draper, Monck, Oakely, Town of Bracebridge, as at December 31, 1970.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Town of Bracebridge, as more particularly set out in Licence No. ED-2002-0540.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One industrial customer located at 154 Beaumont Drive, Bracebridge, ON.

Name of Municipality:	**Town of Bradford-West Gwillimbury**
Formerly Known As:	Town of Bradford, Township of West Gwillimbury, as at December 31, 1990.
Area Not Served By Networks:	The area served by PowerStream Inc. as particularly set out in Licence No. ED-2004-0420, previously served by Barrie Hydro Distribution Inc. described as the former Town of Bradford as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**County of Brant (Initially known as City of Brant-on-the-Grand)**
Formerly Known As:	County of Brant, Town of Paris, Township of Brantford, Township of Burford, Township of Oakland, Township of Onondaga, Township of South Dumfries, as at December 31, 1998.
Area Not Served By Networks:	The area served by Brant County Power Inc. described as the former Village of Burford, the former Town of Paris, the former Township of Brantford and the former Police Village of St. George (in the former Township of South Dumfries) as more particularly set out in Licence No. ED-2002-0522. The area served by Cambridge and North Dumfries Hydro Inc. as particularly set out in Licence No. ED-2002-0574.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Brock**
Formerly Known As:	Village of Beaverton, Village of Cannington, Township of Brock, Township of Thorah, as at December 31, 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Villages of Beaverton and Cannington and the former Police Village of Sunderland (in the former Township of Brock) as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Brockton**
Formerly Known As:	Township of Greenock, Township of Brant, Town of Walkerton, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Walkerton and the portion of the former Police Village of Elmwood (in the former Township of Brant) as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Brooke-Alvinston**
Formerly Known As:	Township of Brooke, Village of Alvinston
Area Not Served By Networks:	The area served by Bluewater Power Distribution Corp. described as the former Village of Alvinston as more particularly set out in Licence No. ED-2002-0517.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Central Elgin**
Formerly Known As:	Township of Yarmouth, Village of Belmont, Village of Port Stanley, as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the former Villages of Belmont and Port Stanley as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Central Huron**
Formerly Known As:	Township of Goderich, Township of Hullett, Town of Clinton, as at December 31, 2000.
Area Not Served By Networks:	The area served by Clinton Power Corporation described as the former Town of Clinton as more particularly set out in Licence No. ED-2002-0496..

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Centre Wellington**
Formerly Known As:	Town of Fergus, Village of Elora, Township of West Garafraxa, Township of Nichol, Township of Pilkington, as at December 31, 1998.
Area Not Served By Networks:	The area served by Centre Wellington Hydro Ltd. described as the former Town of Fergus and the former Village of Elora as more particularly set out in Licence No. ED-2002-0498.
Networks Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Chatham-Kent**
Formerly Known As:	City of Chatham, County of Kent, Town of Blenheim, Town of Bothwell, Town of Dresden, Town of Ridgetown, Town of Tilbury, Town of Wallaceburg, Village of Erie Beach, Village of Erieau, Village of Highgate, Village of Thamesville, Village of Wheatley, Township of Camden, Township of Chatham, Township of Dover, Township of Harwich, Township of Howard, Township of Orford, Township of Raleigh, Township of Rodney, Township of Tilbury East, Township of Zone, as at December 31, 1997.
Area Not Served By Networks:	The area served by Chatham-Kent Hydro Inc. described as the former City of Chatham, former Police Village of Merlin (straddling the former townships of Raleigh and Tilbury East), former Village of Erieau, former Village of Thamesville, former Town of Bothwell, former Village of Wheatley, former Town of Dresden, former Town of Blenheim,

	former Town of Tilbury, former Town of Ridgetown, and the former Town of Wallaceburg as more particularly set out in Licence No. ED-2002-0563.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Clarington**
Formerly Known As:	Town of Bowmanville, Village of Newcastle, Township of Clarke, Township of Darlington, as at December 31, 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Bowmanville, the former Police Village of Orono (in the former Township of Clarke), the former Town of Newcastle as more particularly set out in Licence No. ED-2002-0503
N**etworks assets within area not served by Networks:**	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 410 Waverley Road, Bowmanville ON.

Name of Municipality:	**Township of Clearview**
Formerly Known As:	Town of Stayner, Village of Creemore, Township of Nottawasaga, Township of Sunnidale, as at December 31, 1993.
Area Not Served By Networks:	The area served by COLLUS Power Corp. described as the former Town of Stayner and the former Village of Creemore as more particularly set out in Licence No. ED-2002-0518.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Cochrane**
Formerly Known As:	Town of Cochrane, Township of Glackmeyer, Unorganized Twp. of Lamarche, as at December 31, 1999.
Area Not Served By Networks:	The area served by Northern Ontario Wires Inc. described as the former Town of Cochrane as more particularly set out in Licence No. ED-2002-0018
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Cramahe**
Formerly Known As:	Village of Colborne, Township of Cramahe, as at December 31, 2000.
Area Not Served By Networks:	The area served by Lakefront Utilities Inc. described as the former Village of Colborne as more particularly set out in Licence No. ED-2002-0545.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Dutton/Dunwich**
Formerly Known As:	Township of Dunwich, Village of Dutton, as at December 31, 1997.
Area Not Served By Networks:	The area served by Dutton Hydro Limited described as the former Village of Dutton as more particularly set out in Licence No. ED-2003-0025.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of East Gwillimbury as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Newmarket-Tay Power Distribution Ltd. as particularly set out in Licence No. ED- 2007-0624.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of East Luther Grand Valley**
Formerly Known As:	Township of East Luther, Village of Grand Valley, as at December 31, 1994.
Area Not Served By Networks:	The area served by Orangeville Hydro Limited described as the former Village of Grand Valley as more particularly set out in Licence No. ED-2002-0500.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Township of East Zorra-Tavistock**
Formerly Known As:	Township of East Zorra, Town of Tavistock, as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Town of Tavistock as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Edwardsburgh/Cardinal**
Formerly Known As:	Village of Cardinal, Township of Edwardsburgh, as at December 31, 2000.
Area Not Served By Networks:	The area served by Rideau St. Lawrence Distribution Inc. described as the former Village of Cardinal as more particularly set out in Licence No. ED-2003-0003.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Essa as at March 31, 1999**.
Formerly Known As:	Same

Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as the former Police Village of Thorton as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Essex**
Formerly Known As:	Town of Essex, Town of Harrow, Township of North Colchester, Township of South Colchester, as at December 31, 1998.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Town of Essex and the former Town of Harrow as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Gravenhurst**
Formerly Known As:	Formerly the Township of Morrison, the United Townships of Medora and Wood, the Township of Muskoka, the Township of Ryde, the Town of Gravenhurst, as at December 31, 1970.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former urban boundary of the Town of Gravenhurst as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No
Name of Municipality:	**City of Greater Sudbury**
Formerly Known As:	Region of Sudbury, City of Sudbury, City of Valley East, Town of Capreol, Town of Nickel Centre, Town of Onaping Falls, Town of Rayside-Balfour, Town of Walden, as at December 31, 2000.
Area Not Served By Networks:	The area served by Greater Sudbury Hydro Inc. described as the former City of Sudbury, the former townsite of the former Town of Capreol, and the former Town of Conniston (part of former Town of Nickel Centre) as more particularly set out in Licence No. ED-2002-0559.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of Guelph/Eramosa**
Formerly Known As:	Township of Guelph, Township of Eramosa, as at December 31, 1998.
Area Not Served By Networks:	The area served by Guelph Hydro Electric Systems Inc. as more particularly set out in Licence No. ED-2002-0565.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Hamilton**
Formerly Known As:	Region of Hamilton-Wentworth, City of Hamiton, City of Stoney Creek, Town of Ancaster, Town of Dundas, Town of Flamborough, Township of Glanbrook, as at December 31, 2000.
Area Not Served By Networks:	The area served by Horizon Utilities Corp. described as the former City of Hamilton, the former Police Village of Ancaster, former Town of Dundas, the former Police Village of Lynden (straddling the former Town of Flamborough and Town of Ancaster), the former Village of Waterdown, and the former City of Stoney Creek as more particularly set out in Licence No. ED-2006-0031.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Hawkesbury as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Hydro Hawkesbury Inc. described as the Town of Hawkesbury prior to annexation or amalgamation pursuant to the Minister's Order or Restructuring Act as more particularly set out in Licence No. ED-2003-0027.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Huntsville**
Formerly Known As:	Township of Brunel, Village of Port Sydney, Town of Chaffey, Township of Stephenson, Township of of Stisted, Town of Huntsville, as at December 31, 1970.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Town of Huntsville as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 61 Domtar Road, Huntsville ON.

Name of Municipality:	**Municipality of Huron East**
Formerly Known As:	Village of Brussels, Township of Grey, Township of McKillop, Town of Seaforth, Township of Tuckersmith, as at December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Village of Brussels and the former Town of Seaforth as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Huron-Kinloss**
Formerly Known As:	Township of Huron (former Police Village of Ripley amalgamated with twp in 1995), Township of Kinloss, Village of Lucknow, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former

	Police Village of Ripley (in the former Township of Huron) and the former Village of Lucknow as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Huron Shores**
Formerly Known As:	Township of Day & Bright Add'l, Township of Thessalon, Township of Thompson, Village of Iron Bridge, as at December 31, 1998.
Area Not Served By Networks:	The area served by Great Lakes Power Limited described as part of the former Township of Thessalon or as more particularly set out in Licence No. ED-1999-0227
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Ingersoll**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the Town of Ingersoll as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Iroquois Falls as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Northern Ontario Wires Inc. described as the Town of Iroquois Falls as more particularly set out in Licence No. ED-2002-0018.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Kenora**
Formerly Known As:	Town of Kenora, Town of Keewatin, Town of Jaffray Melick, as at December 31,1999.
Area Not Served By Networks:	The area served by Kenora Hydro Electric Corporation Ltd. described as the former Town of Kenora and part of the former Town of Keewatin as more particularly set out in Licence No. ED-2003-0030.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Killaloe, Hagarty and Richards**
Formerly Known As:	Township of Hagarty and Richards, Village of Killaloe, as at June 30, 1999

Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Village of Killaloe as more particularly set out in Licence No. ED-2002-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Kincardine**
Formerly Known As:	Town of Kincardine, Township of Bruce (Village of Tiverton, Township of Bruce amalgamation), Township of Kincardine, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Kincardine as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of King as at March 31, 1999**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by PowerStream Inc. as more particularly set out in Licence No. ED-2004-0420. The area served by Newmarket-Tay Power Distribution Ltd. as more particularly set out in Licence No. ED-2007-0624.

Networks assets within area not served by Networks: Yes

Customer(s) within area not Served by Networks: No

Name of Municipality:	**City of Kingston**
Formerly Known As:	City of Kingston, Township of Kingston, Township of Pittsburgh, as at December 31, December 31, 1997.
Area Not Served By Networks:	The area served by Kingston Electricity Distribution Ltd. described as the former City of Kingston, the former Township of Kingston, and part of the former Township of Pittsburgh as more particularly set out in Licence No. ED-2003-0057. The area served by Canadian Niagara Power Inc. described as part of the former Township of Pittsburgh as more particularly set out in Licence No. ED-2002-0572.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Kingsville**
Formerly Known As:	Town of Kingsville, Township of Gosfield North, Township of Gosfield South, as at December 31, 1997.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Town of Kingsville and the former Police Village of Cottam (in the former Township of Gosfield North), including Part Lot 269 Part 1 12R-23403, Part Lot 268 Part 1 12R-23674 and Part Lot 269RP 12R-1331 Parts 4

	and 5 located at 168 Belle River Road North, as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Lakeshore**
Formerly Known As:	Township of Lakeshore, (Jan 1998: Town of Belle River, Township of Maidstone amalgamated into Lakeshore Township), Township of Rochester, Township of Tillbury North, Township of Tillbury West, as at December 31, 1998.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Police Village of Comber (in the former Township of Tillbury West) and the former Town of Belle River as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Leamington**
Formerly Known As:	Town of Leamington, Township of Mersea, as at December 31, 1998.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Leamington as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of Leeds and the Thousand Islands**
Formerly Known As:	Township of Front of Leeds and Lansdowne, Township of Rear of Leeds and Lansdowne, Township of Front of Escott, as at December 31, 2000.
Area Not Served By Networks:	The area served by Canadian Niagara Power Inc. described as part of the former Township of the Front of Leeds and Lansdowne as more particularly set out in Licence No. ED-2002-0572.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Municipality of Magnetawan**
Formerly Known As:	Township of Chapman, Village of Magnetawan, Unorganized Township of Croft, as at December 31, 1997.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Village of Magnetawan as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Minto**
Formerly Known As:	Township of Minto, Town of Palmerston, Town of Harriston, Village of Clifford, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Harriston, the former Town of Palmerston, and the former Village of Clifford as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Corporation of the Town of Mississippi Mills**
Formerly Known As:	Town of Almonte, Township of Pakenham, Township of Ramsay, as at December 31, 1998.
Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Town of Almonte as more particularly set out in Licence No. ED-2003-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of New Tecumseth**
Formerly Known As:	Town of Alliston, the Village of Beeton, the Village of Tottenham and the portion of the Township of Tecumseth, as at December 31, 1991.
Area Not Served By Networks:	The area served by PowerStream Inc. described as the former Town of Alliston, the former Village of Beeton and the former Village of

	Tottenham (all in the former Township of Tecumseth) as more particularly set out in Licence No. ED-2004-0420.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located in the former Town of Alliston.

Name of Municipality:	**The Corporation of Norfolk County**
Formerly Known As:	Township of Norfolk, Township of Delhi, Town of Simcoe, City of Nanticoke (westerly 'half' only), as at December 31, 2000.
Area Not Served By Networks:	The area served by Norfolk Power Distribution Inc. described as the former Town of Delhi (in the former Township of Delhi), the westerly half of the former City of Nanticoke, the former Village of Port Rowan (in former Township of Norfolk), and the former Town of Simcoe as more particularly set out in Licence No. ED-2002-0521.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at Lake Erie and Regional Rd.. 3, Nanticoke, ON.

Name of Municipality:	**Township of North Huron**
Formerly Known As:	Town of Wingham, Village of Blyth, Township of East Wawanosh,as at December 31, 2000.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Wingham as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	Two Industrial customers located at 40621 Amberly Rd., and 200 Water Street Wingham, ON.

Name of Municipality:	**Municipality of North Middlesex**
Formerly Known As:	Township of McGillivray, Township of East Williams, Township of West Williams, Town of Parkhill, Village of Ailsa Craig, as at December 31, 2000.
Area Not Served By Networks:	The area served by Middlesex Power Distribution Corp. described as the former Town of Parkhill as more particularly set out in Licence No. ED-2003-0059.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Township of Norwich as at March 31, 1999**.
Formerly Known As:	Township of North Norwich, Township of South Norwich, Township of East Oxford, Village of Norwich, Village of Burgessville, and Police Village of Otterville, as at
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Norwich, the former Village of Burgessville, and the former Police Village of Otterville as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Ottawa**
Formerly Known As:	Region of Ottawa-Carleton, City of Gloucester, City of Kanata, City of Nepean, City of Ottawa, City of Vanier, Township of Cumberland, Township of Goulbourn, Township of Osgoode, Township of Rideau, Township of West Carleton, Village of Rockcliffe Park, as at December 31, 2000.
Area Not Served By Networks:	The area served by Hydro Ottawa Limited described as the former City of Gloucester, the former City of Kanata, the former City of Nepean, the former City of Ottawa, the former City of Vanier, the former Township of Goulbourn, the former Village of Rockcliffe Park, and the portion of the former Township of Rideau on Long Island, North of Bridge Street, as more particularly set out in Licence No. ED-2002-0556.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No.

Name of Municipality:	**Town of Pelham**
Formerly Known As:	Township of Pelham, Village of Fonthill, as at December 31, 1969.
Area Not Served By Networks:	The area served by Niagara Peninsula Energy Inc.described as the former Village of Fonthill as more particularly set out in Licence No. ED-2002-0555.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Perth East**
Formerly Known As:	Township of Mornington, Township of Ellice, Township of North Easthope, Township of South Easthope, Village of Milverton, as at December 31, 1997.
Area Not Served By Networks:	The area served by Festival Hydro Inc. as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Peterborough as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Peterborough Distribution Inc. described as the City of Peterborough as more particularly set out in Licence No. ED-2002-0504.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Port Hope**
Formerly Known As:	Town of Port Hope, Township of Hope (initially restructured as Municipality of Port Hope and Hope), as at December 31, 2000.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Port Hope as more particularly set out in Licence No. ED-

	2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Puslinch as at March 31, 1999**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Guelph Hydro Electric Systems Inc. as more particularly set out in Licence No. ED-2002-0565.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Red Lake**
Formerly Known As:	Township of Red Lake, Township of Golden, as at June 30, 1997.
Area Not Served By Networks:	The area served by Gold Corp Inc. described as part of the former Improvement District of Balmertown.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Russell as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Cooperative Hydro Embrun Inc. described as the

	former Police Village of Embrum as more particularly set out in Licence No. ED-2002-0493.
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Sables-Spanish Rivers**
Formerly Known As:	Town of Massey, Town of Webbwood, Township of the Spanish River, as at June 30, 1997.
Area Not Served By Networks:	The area served by Espanola Regional Hydro Distribution Corp. described as the former Town of Massey and the former Town of Webbwood as more particularly set out in Licence No. ED-2002-0502.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Saugeen Shores**
Formerly Known As:	Township of Saugeen, Town of Southampton, Town of Port Elgin, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Southampton and the former Town of Port Elgin as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not	

served by Networks:	No
Name of Municipality:	**City of St. Thomas as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by St. Thomas Energy Inc. described as the City of St. Thomas as more particularly set out in Licence No. ED-2002-0523.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 1 Cosma Court
Name of Municipality:	**Township of Scugog**
Formerly Known As:	Township of Scugog, Township of Cartwright, Township of Reach, Village of Port Perry, as at December 31. 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Village of Port Perry as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Municipality of Sioux Lookout**
Formerly Known As:	Town of Sioux Lookout, as at December 31, 1997
Area Not Served By Networks:	The area served by Sioux Lookout Hydro Inc. described as the Municipality of Sioux Lookout as more particularly set out in Licence No. ED-2002-0514.
Networks assets within area	

not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: **Township of Smith-Ennismore-Lakefield**

Formerly Known As: Village of Lakefield, Township of Smith-Ennismore (formerly Township of Smith and Township of Ennismore), as at December 31, 2000.

Area Not Served By Networks: The area served by Peterborough Distribution Inc. described as the former Village of Lakefield as more particularly set out in Licence No. ED-2002-0504.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: **Municipality of South Bruce**

Formerly Known As: Township of Mildmay-Carrick, Township of Teeswater-Culross, (Jan 1998: Village of Teeswater, Township of Culross amalgamated into the Township of Teeswater-Culross. Village of Mildmay, Township of Carrick amalgamated into the Township of Mildmay-Carrick), as at December 31, 1997.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Village of Mildmay and the former Village of Teeswater as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality:	**Township of South Dundas**
Formerly Known As:	Township of Matilda, Township of Williamsburg, Village of Iroquois, Village of Morrisburg, as at December 31, 1997.
Area Not Served By Networks:	The area served by Rideau St. Lawrence Distribution Inc. described as the former Police Village of Williamsburg, the former Village of Morrisburg, and the former Village of Iroquois as more particularly set out in Licence No. ED-2003-0003.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of South Glengarry**
Formerly Known As:	Township of Charlottenburgh, Township of Lancaster, Village of Lancaster, Police Village of Martintown, as at December 31, 1997.
Area Not Served By Networks:	The area served by the Cornwall Street Railway Light and Power Company Limited described as part of the former Township of Charlottenburgh as more particularly set out in Licence No. ED-2004-0405.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	**Three Solar PV generator customers located at:** 1. Part of Lots 5 & 6, Concession 5 2. Part of Lots 15 & 16, Concession 5 & 6 3. Lot 41, 41A, Plan 107 except Part 20 and 20A on 14R299, s/t IL 3007, TCH 4416 and Plan 107 – Pt Lot 40 as in AR 1461, Except Pt 1 & 2, 14R2143 S/T TCH 4357

Name of Municipality:	**Municipality of South Huron**
Formerly Known As:	Township of Stephen, Township of Usborne, Town of Exeter, as at

	December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Police Village of Dashwood as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of South Stormont**
Formerly Known As:	Township of Osnabruck, Township of Cornwall, as at December 31, 1997
Area Not Served By Networks:	The area served by Cornwall Street Railway Light and Power Company Limited described as part of the former Township of Cornwall and part of the former Township of Osnabruk as more particularly set out in Licence No. ED-2004-0405.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Southgate**
Formerly Known As:	Village of Dundalk, Township of Egremont, Township of Proton, Police Village of Holstein, as at December 31, 1999.
Area Not Served By Networks:	The area served by Wellington North Power Inc. described as the former Police Village of Holstein as more particularly set out in Licence No. ED-2002-0511.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Township of South-West Oxford**
Formerly Known As:	Township of West Oxford, Township of Dereham, Village of Beachville, as at December 31,. 1974.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Beachville as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Stratford**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Festival Hydro Inc. as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Strathroy-Caradoc**
Formerly Known As:	Town of Strathroy, Township of Caradoc**,** as at December 31, 2000.
Area Not Served By Networks:	The area served by Middlesex Power Distribution Corp. described as the former Police Village of Mount Brydges (in the former Township of Caradoc) and the former Town of Strathroy as more particularly set out in Licence No. ED-2003-0059.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Tay**
Formerly Known As:	Village of Port NcNicoll, Village of Victoria Harbour, the Township of Medonte, Township of Tay, Township of Tiny, Township of Flos, Police Village of Waubaushene, as at December 31, 1996.
Area Not Served By Networks:	The area served by Newmarket-Tay Power Distribution Ltd. as more particularly set out in Licence No. ED-2007-0624.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Tecumseh**
Formerly Known As:	Town of Tecumseh, Village of St. Clair Beach, Township of Sandwich South, as at December 31, 1998.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Tecumseh and the former Village of St. Clair Beach as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Uxbridge**
Formerly Known As:	Town of Uxbridge, Township of Scott, Township of Uxbridge, as at December 31. 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Uxbridge as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Warwick**
Formerly Known As:	Village of Watford, Township of Warwick, as at December 31, 1997.
Area Not Served By Networks:	The area served by Bluewater Power Distribution Corp. described as the former Village of Watford as more particularly set out in Licence No. ED-2002-0517.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Wellington North**
Formerly Known As:	Town of Mount Forest, Village of Arthur, Township of Arthur, Township of West Luther, as at December 31, 1998.
Area Not Served By Networks:	The area served by Wellington North Power Inc. described as the former Village of Arthur and the former Town of Mount Forest as more particularly set out in Licence No. ED-2002-0511.

Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of West Grey**
Formerly Known As:	Township of West Grey, Town of Durham (Jan 2000 Township Bentinck, Township of Glenelg, Town Normanby, Village of Neustadt amalgamated into the Township of West Grey), as at December 31, 1999.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Village of Neustadt and a portion of the former Police Village of Elmwood (in the former Township of Bentinck) as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of West Nipissing**
Formerly Known As:	Town of Cache Bay, Town of Sturgeon Falls, Township of Caldwell, Township of Field, Township of Springer, as at December 31, 1998.
Area Not Served By Networks:	The area served by West Nipissing Energy Services Ltd. described as the former Town of Cache Bay and the former Town of Sturgeon Falls as more particularly set out in Licence No. ED-2002-0562.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of West Perth**
Formerly Known As:	Township of Logan, Township of Fullarton, Township of Hibbert, Town of Mitchell, Police Village of Dublin, as at December 31, 1997.
Area Not Served By Networks:	The area served by West Perth Power Inc. described as the former Town of Mitchell and the former Police Village of Dublin as more particularly set out in Licence No. ED-2002-0508.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Whitby**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Whitby Hydro Electric Corporation and the area served by Veridian Connections Inc. as more particularly set out in Licence No. ED-2002-0571.

Name of Municipality:	**Township of Whitewater Region**
Formerly Known As:	Township of Ross, Township of Westmeath, Village of Beachburg, Village of Cobden, as at December 31, 2000.
Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Village of Beachburg as more particularly set out in Licence No. ED-2003-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Woodstock as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Woodstock Hydro Services Inc. described as the City of Woodstock as more particularly set out in Licence No. ED-

	2003-0011, including the Boot Hill Development located on part of lots 3, 7, 8, 11, 12, 13 and registered plan 86 and 501, and three customers on Mill Street with civic address numbers 388, 390 and 410.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Zorra**
Formerly Known As:	Township of West Zorra, Township of East Nissouri, Township of North Oxford, Village of Embro, Village of Thamesford , as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Embro and the former Village of Thamesford as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Town of Penetanguishene as at March 31, 1999**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as part of the Town of Penetanguishene as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

APPENDIX B

TAB 5 CONSUMERS EMBEDDED WITHIN ANOTHER DISTRIBUTOR BUT SERVED BY THE LICENSEE

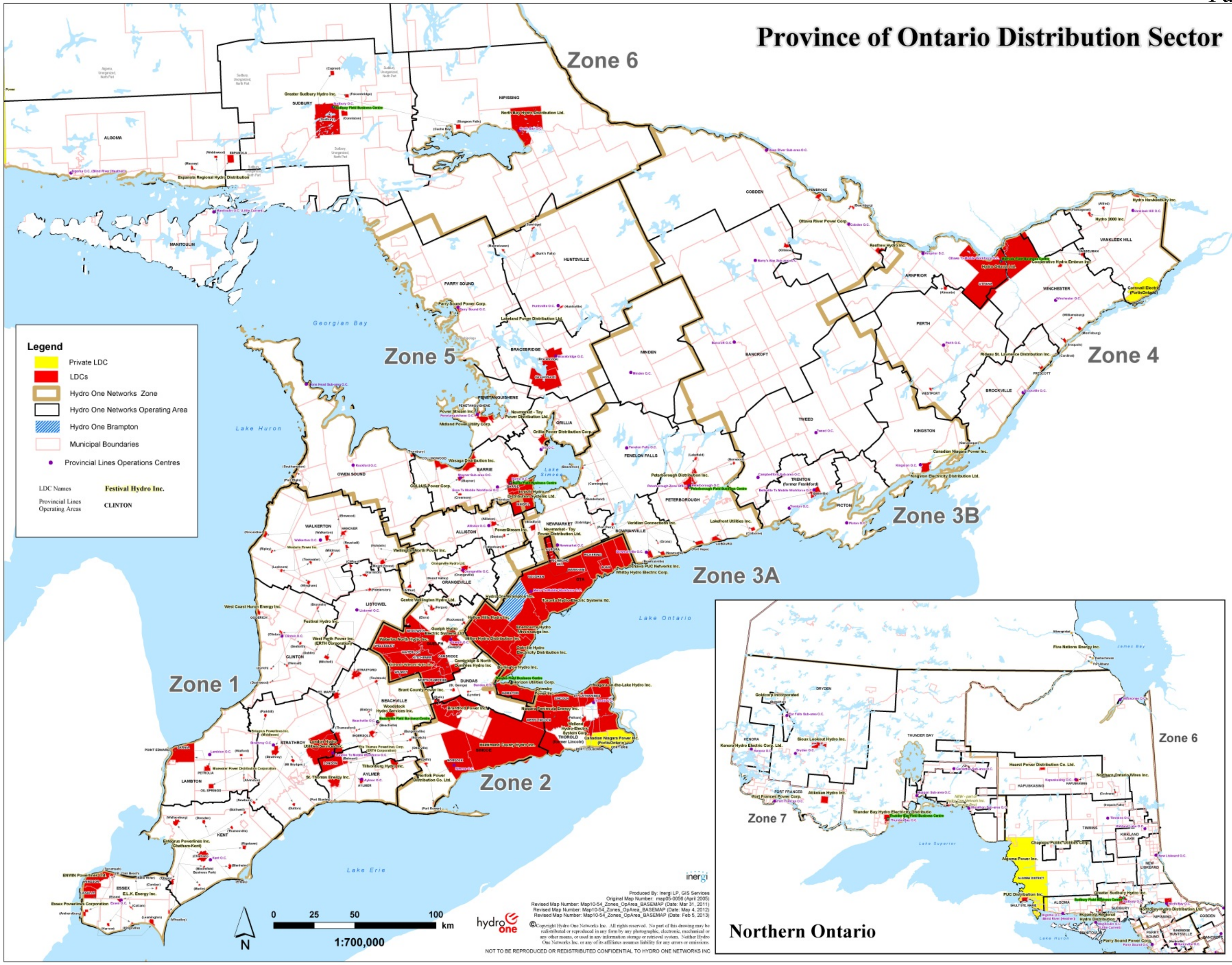
(Note also that each municipality noted in Tab 5 is a municipality served almost entirely by another distributor but in which the Licensee serves one or more consumers.)

Name of Municipality:	**City of Cornwall**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	The customers located at 501 Wallrich Avenue.

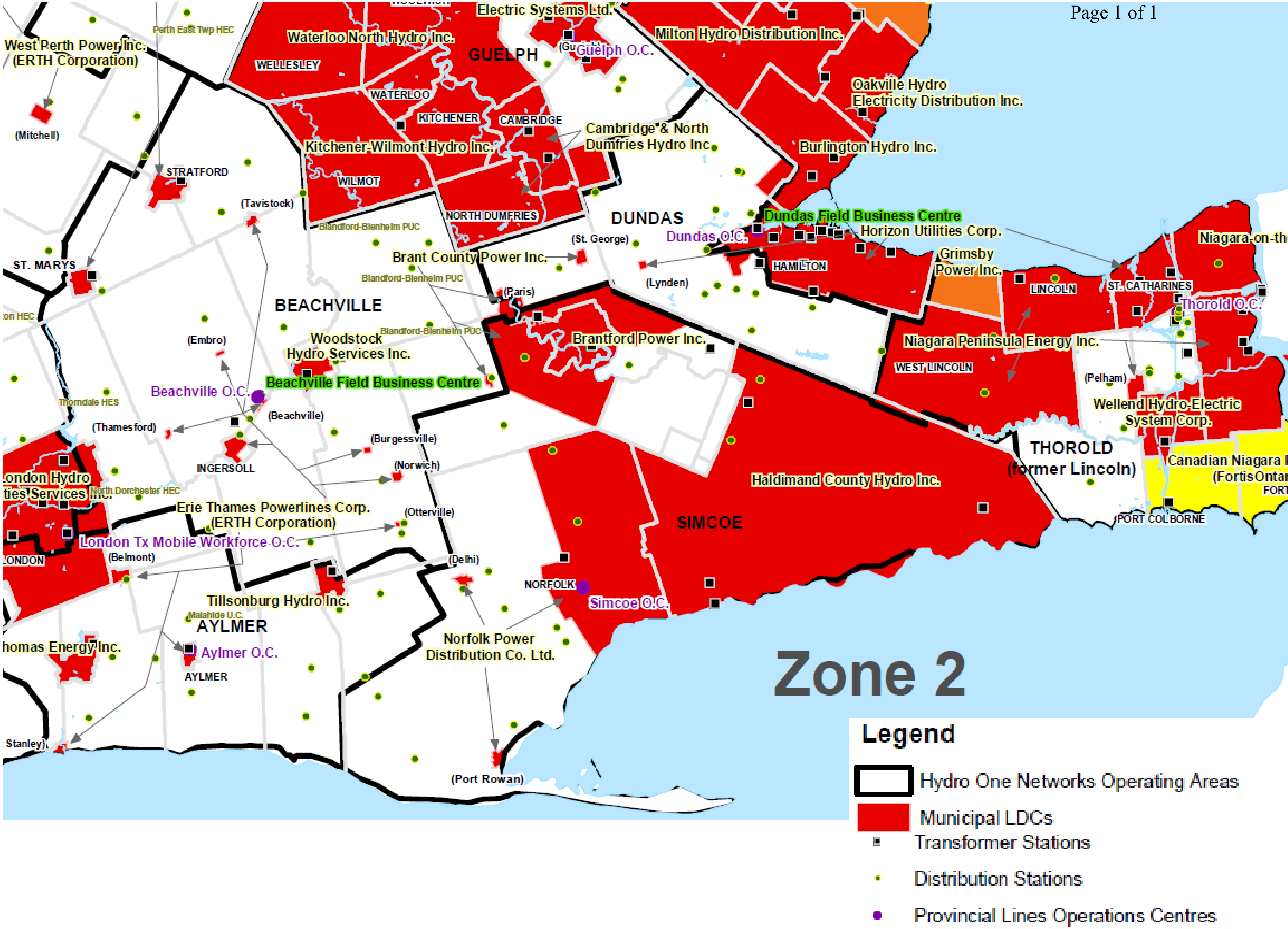
Name of Municipality:	**County of Haldimand**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One customer located in Caledonia, Ont.

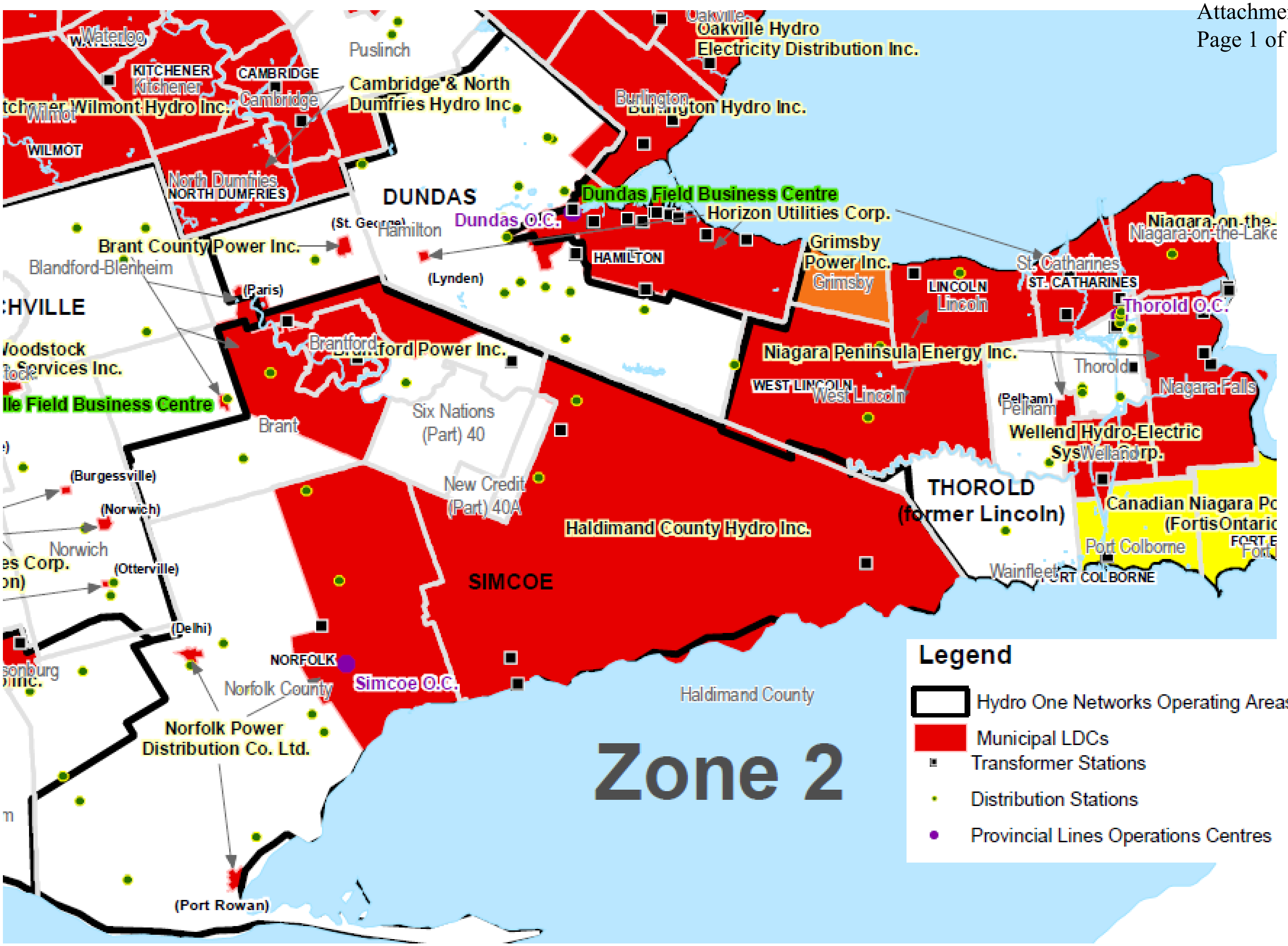
Name of Municipality:	**City of Niagara Falls**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	Three customers located at 8001 Daly Street, 7780 Stanley Ave, 6225 Progress Street

Name of Municipality:	**City of St. Thomas**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One industrial customer located at 1 Cosma Court.

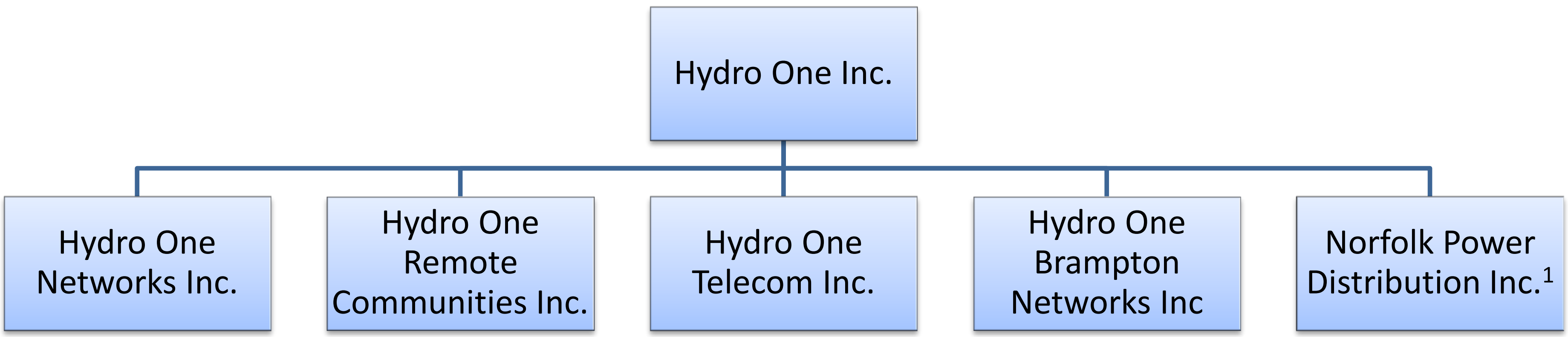


Province of Ontario Distribution Sector
Zone 6
Zone 5
Zone 4
Zone 3B
Zone 3A
Zone 2
Zone 1
Legend
Private LDC
LDCs
Hydro One Networks Zone
Hydro One Networks Operating Area
Hydro One Brampton
Municipal Boundaries
Provincial Lines Operations Centres
LDC Names
Festival Hydro Inc.
Provincial Lines Operating Areas
CLINTON
Georgian Bay
Lake Huron
Lake Ontario
Lake Erie
0 25 50 100 km
1:700,000
N
Northern Ontario
Zone 7
Zone 6
Lake Superior
James Bay
NOT TO BE REPRODUCED OR REDISTRIBUTED CONFIDENTIAL TO HYDRO ONE NETWORKS INC


Electric Systems Ltd.
Waterloo North Hydro Inc.
GUELPH
Guelph O.C.
Milton Hydro Distribution Inc.
West Perth Power Inc.
(ERTH Corporation)
Perth East Twp HEC
WELLESLEY
WATERLOO
KITCHENER
CAMBRIDGE
Oakville Hydro
Electricity Distribution Inc.
(Mitchell)
Cambridge & North
Dumfries Hydro Inc.
Kitchener-Wilmont Hydro Inc.
Burlington Hydro Inc.
STRATFORD
WILMOT
(Tavistock)
NORTH DUMFRIES
DUNDAS
Dundas Field Business Centre
Blandford-Blenheim PUC
(St. George)
Dundas O.C.
Horizon Utilities Corp.
Niagara-on-the-
Brant County Power Inc.
Grimsby
Power Inc.
ST. MARYS
HAMILTON
Blandford-Blenheim PUC
(Lynden)
LINCOLN
ST. CATHARINES
(Paris)
Thorold O.C.
BEACHVILLE
Woodstock
Hydro Services Inc.
Blandford-Blenheim PUC
Brantford Power Inc.
Niagara Peninsula Energy Inc.
(Embro)
WEST LINCOLN
Beachville Field Business Centre
(Pelham)
Beachville O.C.
Thorndale HES
(Beachville)
Wellend Hydro-Electric
System Corp.
(Thamesford)
(Burgessville)
THOROLD
(former Lincoln)
INGERSOLL
(Norwich)
Canadian Niagara Po
(FortisOntario
FORT E
London Hydro
ties Services Inc.
North Dorchester HEC
Haldimand County Hydro Inc.
Erie Thames Powerlines Corp.
(ERTH Corporation)
(Otterville)
PORT COLBORNE
SIMCOE
London Tx Mobile Workforce O.C.
LONDON
(Belmont)
(Delhi)
NORFOLK
Tillsonburg Hydro Inc.
Simcoe O.C.
Malahide U.C.
AYLMER
Aylmer O.C.
homas Energy Inc.
Norfolk Power
Distribution Co. Ltd.
AYLMER
Zone 2
Stanley)
(Port Rowan)
Legend
Hydro One Networks Operating Areas
Municipal LDCs
Transformer Stations
Distribution Stations
Provincial Lines Operations Centres


Zone 2
Legend
Hydro One Networks Operating Areas
Municipal LDCs
Transformer Stations
Distribution Stations
Provincial Lines Operations Centres
DUNDAS
SIMCOE
THOROLD
(former Lincoln)
Oakville Hydro
Electricity Distribution Inc.
Cambridge & North
Dumfries Hydro Inc.
Burlington Hydro Inc.
Dundas Field Business Centre
Horizon Utilities Corp.
Grimsby
Power Inc.
Niagara-on-the-Lake
St. Catharines
Thorold O.C.
Dundas O.C.
Brant County Power Inc.
Blandford-Blenheim
Brantford Power Inc.
Niagara Peninsula Energy Inc.
Six Nations
(Part) 40
New Credit
(Part) 40A
Haldimand County Hydro Inc.
Wellend Hydro-Electric
Niagara Falls
Port Colborne
Wainfleet
Norfolk Power
Distribution Co. Ltd.
Simcoe O.C.
Norfolk County
Haldimand County
Puslinch
Hamilton
(Lynden)
(Paris)
(Burgessville)
(Norwich)
(Otterville)
(Delhi)
(Port Rowan)
Norwich
Brant
NORFOLK
HAMILTON
LINCOLN
WEST LINCOLN
ST. CATHARINES
(Pelham)
KITCHENER
CAMBRIDGE
WILMOT
NORTH DUMFRIES

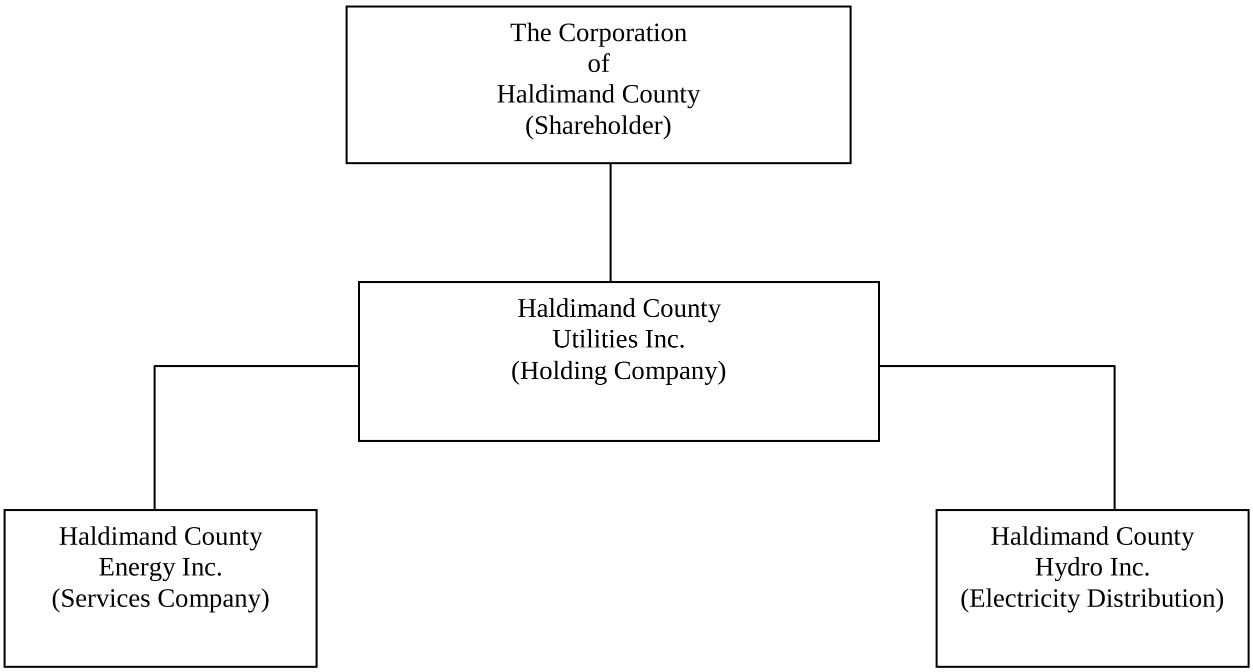
Hydro One Inc. Corporate Structure



Notes:

[1]Subject to transaction closing.

CORPORATE STRUCTURE



1908872 ONTARIO INC.
(the "Purchaser")

- and -

THE CORPORATION OF HALDIMAND COUNTY
(the "Vendor")

- and -

HYDRO ONE INC.
(the "Indemnitor")

SHARE PURCHASE AGREEMENT

Dated the 10th day of June, 2014

SHARE PURCHASE AGREEMENT

THIS AGREEMENT is made on the 10th day of June, 2014.

B E T W E E N:

THE CORPORATION OF HALDIMAND COUNTY, a corporation incorporated under the laws of Ontario,

(the "**Vendor**")

- and -

1908872 ONTARIO INC., a corporation incorporated under the laws of Ontario,

(the "**Purchaser**")

- and -

HYDRO ONE INC., a corporation incorporated under the laws of Ontario,

(the "**Indemnitor**")

(each a "**Party**" and collectively, the "**Parties**")

WHEREAS Haldimand County Hydro Inc. (the "**LDC**") is a corporation incorporated under the *Business Corporations Act* (Ontario) licensed by the Ontario Energy Board to distribute electricity in Ontario and is a wholly-owned subsidiary of the Vendor;

AND WHEREAS the LDC and Haldimand County Energy Inc. ("**HCEI**") are corporations incorporated under the *Business Corporations Act* (Ontario) and each is a wholly-owned subsidiary of Haldimand County Utilities Inc. ("**HCUI**"), itself incorporated under the *Business Corporations Act* (Ontario);

AND WHEREAS HCUI is a wholly-owned subsidiary of the Vendor;

AND WHEREAS the Vendor is the beneficial and registered owner of all of the issued and outstanding shares of HCUI;

AND WHEREAS the Purchaser is a wholly owned subsidiary of the Indemnitor;

AND WHEREAS the Vendor wishes to sell to the Purchaser, and the Purchaser wishes to purchase from the Vendor, all of the issued and outstanding shares of HCUI, on and subject to the terms and conditions set forth herein;

AND WHEREAS such purchase of the shares of HCUI by Purchaser and all related obligations will be fully indemnified by the Indemnitor;

THIS AGREEMENT WITNESSES THAT, in consideration of the respective covenants, agreements, representations and warranties of the Parties herein contained and for other good and valuable consideration (the receipt and sufficiency of which are acknowledged by each Party), the Parties covenant and agree as follows:

ARTICLE I
INTERPRETATION

1.1 **Defined Terms.** In this Agreement, including the recitals, Schedules and Exhibits hereto, unless the context otherwise specifies or requires, the following terms shall have the respective meanings specified or referred to below and grammatical variations of such terms shall have corresponding meanings:

(a) "**Advisory Committee**" has the meaning ascribed thereto in Section 6.4;

(b) "**Affiliate**" has the meaning ascribed thereto in the OBCA but extends to non-corporate entities under a similar degree of control;

(c) "**Agreement**" means this share purchase agreement, including all Schedules, Appendices and Exhibits to this agreement, as amended from time to time in accordance with its provisions;

(d) "**Applicable Law**" means any and all applicable laws, statutes, codes, licensing requirements, directives, rules, guidelines, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any Governmental Authority, including without limitation, the OEB, but excluding, any such directive, guideline or requirement not having the force of law;

(e) "**Auditors' Supporting Documentation**" has the meaning set out in Section 2.4(a);

(f) "**Business**" means the business of the LDC, the business of HCEI, the business of HCUI or the business of all of them, as the context may suggest;

(g) "**Business Day**" means a day other than a Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto are not open for business during normal banking hours;

(h) "**Claim**" means any demand, action, cause of action, prosecution, suit, proceeding, claim, assessment, charge, complaint, grievance, order, or judgment or settlement or compromise relating thereto;

(i) "**Closing**" means the completion of the purchase and sale of the Purchased Shares contemplated herein;

(j) "**Closing Date**" means the later of the first date that is the last Business Day of a month and:

(i) at least ninety (90) days following the date that all of the Required Approvals are obtained; or

(ii) follows completion to the satisfaction of Purchaser acting reasonably, including to the extent applicable, commissioning and bringing in-service all of the projects listed in Section 9.1(g).

or such earlier or later date as may be agreed upon in writing by the Parties, provided that in no event shall any such date be on or after December 31, 2015;

(k) "**Closing Date Financial Statements**" means subject to Subsection 2.4(g), audited consolidated financial statements for HCUI for the fiscal period ended on the Closing Date, prepared in accordance with GAAP consistently applied and consisting of a balance sheet as of such date and statements of earnings and retained earnings and of changes in financial position for such period, together with notes thereto as at such date of HCUI's auditors thereon addressed to HCUI, the Vendor, and the Purchaser;

(l) "**Closing Date Net Debt**" shall have the meaning ascribed thereto in Section 2.4(a);

(m) "**Closing Date NFA**" shall have the meaning ascribed thereto in Section 2.4(a);

(n) "**Closing Date Working Capital**" shall have the meaning ascribed thereto in Section 2.4(a);

(o) "**Confidential Information**" has the meaning ascribed thereto in Subsection 6.11(a);

(p) "**Confidentiality Agreement**" means the agreed confidentiality rights and obligations contained in the agreement between HCUI, the LDC, and the Indemnitor dated August 8, 2013;

(q) "**Consolidated Net Debt**" means the sum of loan balances, short term debt and long term debt (excluding customer deposits) less any net cash balances calculated in accordance with Schedule 2.4;

(r) "**Contract**" means any agreement, indenture, contract, lease, deed of trust, licence, option, instrument or other commitment, whether written or oral;

(s) "**CTA**" means with regard to any taxation year in respect of which either is applicable, the *Taxation Act, 2007* (Ontario) or the *Corporations Tax Act* (Ontario) and the respective regulations made thereunder;

(t) "**Current Rates**" has the meaning ascribed thereto in Section 6.6;

(u) "**Customer Operations Manager**" or "**COM**" has the meaning ascribed thereto in Section 6.8;

(v) "**Daily Adjustment Value**" means $315.07;

(w) "**Damages**" means any damages, losses, costs, liabilities or expenses, directly or indirectly incurred, suffered or paid by a Person including economic or consequential damages, reasonable professional fees and reasonable costs incurred in investigating, pursuing or defending a Claim or any of the foregoing, or remediating any adverse environmental condition but, does not include any indirect or consequential damages other than damages of a third party in respect of a Claim by such third party;

(x) "**Data Room**" means the documents delivered by the LDC to Indemnitor by a series of emails from August 20, 2013 to November 8, 2013, and on June 6, 2014 from or on behalf of the President and CEO of HCUI or uploaded by the LDC or HCUI to https://pcs.com/lft/app/data/530096-busdev-rw/usermain.jsp prior to November 8, 2013 and those provided by hyper-drive on March 19, 2014 and April 15, 2014;

(y) "**Decision Period Adjustment Factor**" means a factor equal to one (1) minus the Rate Adjustment Factor;

(z) "**Decision Period Days**" means the number of days, between the Closing Date and the Reduced Rate Effective Date if it occurs after the Closing Date;

(aa) "**Deposit**" has the meaning given to it in Subsection 2.2(a);

(bb) "**Dunnville TS Breakers**" means the breaker position to be installed at the Dunnville TS;

(cc) "**EA**" means the *Electricity Act, 1998* (Ontario), as in effect on the date hereof;

(dd) "**Easements**" has the meaning ascribed thereto in Subsection 3.1(l)(i);

(ee) "**Employee Benefits**" include post-employment benefits and means:

(i) salaries, wages, bonuses, vacation entitlements, commissions, fees, stock option plans, incentive plans, deferred compensation plans, profit-sharing plans, severance plans, termination pay plans, supplementary employment insurance plans and other similar benefits, plans or arrangements;

(ii) insurance, health, welfare, disability, pension, retirement, hospitalization, medical, prescription drug, dental, eye care and other similar benefits, plans or arrangements;

(iii) use of any automobiles or other vehicles or equipment based upon past practice; and

(iv) agreements with any labour union or employee association or employment agreements.

(ff) "**Employees**" has the meaning ascribed thereto in Subsection 3.1(q);

(gg) "**Environment**" means the environment or natural environment as defined in any Environmental Law and includes air, surface water, ground water, land surface, soil, sub-surface strata and sewer system;

(hh) "**Environmental Approvals**" means all permits, certificates, licences, authorizations, consents, registrations, directions, instructions, waste generation numbers or approvals required pursuant to Environmental Laws with respect to real property owned or occupied by any of the Haldimand Corporations or used in the Business, or the operation of any of the Haldimand Corporations or the Business;

(ii) "**Environmental Laws**" means all Applicable Laws relating in whole or in part to the protection of the Environment or to public health and safety, and includes those relating to the manufacture, processing, distribution, use, treatment, storage, disposal, discharge, transportation or handling of Hazardous Substances and in addition, guidelines, directions and requirements which would be Applicable Laws but do not otherwise have the force of law;

(jj) "**ETA**" means Part IX of the *Excise Tax Act* (Canada) and any regulation made thereunder;

(kk) "**Excluded Property**" means the Selkirk DS site comprised of the lands known as 112 Selkirk Street, Caledonia, being CAL Pt Lots 67 E Selkirk, Haldimand County;

(ll) "**Financial Statements**" means the audited consolidated December 31, 2013 financial statements of HCUI prepared in accordance with GAAP;

(mm) "**Five-Year Fixed Amount**" means an amount equal to $575,000;

(nn) "**Fixed Assets**" means fixed assets, furniture, furnishings, parts, tools, personal property, real property, fixtures, plants, buildings, structures, erections, improvements, appurtenances, machinery, equipment, distribution stations, transformers, vaults, meters, distribution lines, conduits, ducts, pipes, wires, rods, cables, fibre optic strands, devices, appliances, material, poles, fittings, sentinel lights, rolling stock and any other similar or related item of the Business;

(oo) "**GAAP**" means the general accounting principles (including the methods of application of such principles) accepted or recommended by CPA Canada I Part V of the CPA Canada Handbook which are applicable in Canada as at December 31, 2013 for rate regulated entities and described in more detail in Note 2 to the Financial Statements;

(pp) "**Governmental Authority**" means any domestic or foreign government, whether federal, provincial, state, territorial, local, regional, municipal, or other political jurisdiction, and any agency, authority, instrumentality court, tribunal, board, commission, bureau, arbitrator, arbitration tribunal or other tribunal, or any quasi-governmental or related entity, insofar as it exercises a valid legislative, judicial, regulatory, administrative, expropriation or taxing power or function of or pertaining to government;

(qq) "**Haldimand Corporations**" means HCUI, HCEI and the LDC;

(rr) "**Hazardous Substances**" means any hazardous substance, or any pollutant, contaminant, toxic or dangerous waste, substance or material, as defined in or regulated by any Environmental Law including, without limitation, friable asbestos and poly-chlorinated biphenyls;

(ss) "**HST**" means all taxes payable under the ETA (including where applicable both the federal and provincial portion of those taxes) or under any provincial legislation imposing a similar value-added or multi-stage tax;

(tt) "**Interim Period**" means the period from December 31, 2013 to the Closing Date;

(uu) "**Licences**" has the meaning ascribed thereto in Subsection 3.1(bb);

(vv) "**Material Adverse Effect**" means any change or effect that has a material adverse effect on the property and assets of the LDC or HCUI taken as a whole or the operations or results of operations of the Business of either taken as a whole, after taking into account any insurance which may be available with respect to such a change or effect;

(ww) "**Material Contract**" means any Contract for the supply of goods or services which has a value exceeding Fifty Thousand Dollars ($50,000.00) in annual payments where the LDC is the contracting party, or a value exceeding Five Thousand Dollars ($5,000) in annual payments where HCUI or HCEI is the contracting party;

(xx) "**Municipality**" means the geographic area comprising Haldimand County as it exists on the date of this Agreement;

(yy) "**Negative Rate Rider**" has the meaning ascribed thereto in Section 6.6(a);

(zz) "**Net Debt**" means the Consolidated Net Debt as adjusted for any positive or negative Net Regulatory Adjustment and calculated in accordance with Schedule 2.4 and the Financial Statements or Closing Date Financial Statements as applicable;

(aaa) "**Net Debt Calculation**" means the written statement setting out the detailed calculation of Closing Date Net Debt in accordance with Schedule 2.4 and the amount by which the Closing Date Net Debt is greater or less than Net Debt shown in. the Financial Statements;

(bbb) "**Net Regulatory Adjustment**" means the product of 0.735 and the difference between regulatory assets/liabilities (including the value of the Dunnville TS Breakers which shall be treated as an asset) and the future taxes included in regulatory liabilities all calculated in accordance with Schedule 2.4, and the Closing Date Financial Statements;

(ccc) "**NFA**" means the aggregate net book value of the property, plant and equipment of the Business, less the deferred credits, (both as set out in the Financial Statements or Closing Date Financial Statements, as applicable) plus the amount of all payments made by the LDC to the Indemnitor attributable to the Dunnville TS Breakers;

(ddd) "**NFA Calculation**" means the difference between the Closing Date NFA and the NFA derived from the Financial Statements;

(eee) "**NFA Index**" shall be equal to 1.5;

(fff) "**OBCA**" means the *Business Corporations Act* (Ontario), as in effect on the date hereof;

(ggg) "**OEB**" means the Ontario Energy Board;

(hhh) "**OEB Act**" means the *Ontario Energy Board Act*, 1998, as in effect on the date hereof;

(iii) "**OEB Approval**" means the OEB approval of the transactions contemplated herein pursuant to the OEB Act;

(jjj) "**OEB Percentage Rate Reduction**" means the difference in the arithmetic average of Current Rates and Reduced Rates, expressed as a percentage of Current Rates and calculated in accordance with the following formula:

((Current Rates - Reduced Rates) ÷ Current Rates) x 100%;

(kkk) "**OMERS**" means the Ontario Municipal Employees Retirement System;

(lll) "**Partial Rate Rider**" means a Negative Rate Rider that results in an OEB Percentage Rate Reduction of less than one percent (1%) averaged across all Rate classes;

(mmm) "**Parties**" means the Purchaser, the Indemnitor and the Vendor and "**Party**" means any one of them;

(nnn) "**PCBs**" has the meaning ascribed thereto in Subsection 3.1(t)(vi);

(ooo) "**Person**" means any individual, partnership, limited partnership, joint venture, syndicate, sole proprietorship, company or corporation with or without share capital, unincorporated association, trust, trustee, executor, administrator or other legal personal representative, regulatory body or agency, government or governmental agency, authority or entity however designated or constituted;

(ppp) "**PILs**" means payment in lieu of Taxes required to be made under the EA;

(qqq) "**Property**" means the property and assets of the Haldimand Corporations;

(rrr) "**Purchaser**" means 1908872 Ontario Inc.;

(sss) "**Purchaser's Objection**" has the meaning ascribed thereto in Subsection 2.4(b);

(ttt) "**Purchase Price**" has the meaning ascribed thereto in Section 2.2;

(uuu) "**Purchased Shares**" has the meaning ascribed thereto in Section 2.1;

(vvv) "**Rate**" or "**Rates**" means the rate or rates established by the OEB for the LDC for the distribution of electricity;

(www) "**Rate Adjustment Difference**" means a difference equal to one percent (1%) minus the OEB Percentage Rate Adjustment in the event that the OEB Percentage Rate Adjustment is less than one percent (1%);

(xxx) "**Rate Adjustment Factor**" means a factor equal to the Rate Adjustment Difference divided by one percent (1%);

(yyy) "**Rate Freeze Period**" means the period commencing on the Closing Date and ending on the date which is five (5) years after the Closing Date;

(zzz) "**Real Property**" has the meaning ascribed thereto in Subsection 3.1(i)(i);

(aaaa) "**Reduced Rate Effective Date**" means the effective date of a Negative Rate Rider or a Partial Rate Rider, as applicable and as approved by the OEB;

(bbbb) "**Reduced Rates**" means the reduced Rates that result from the OEB Approval of a Negative Rate Rider or Partial Rate Rider applicable to the Current Rates;

(cccc) "**Release**" has the meaning ascribed thereto in any Environmental Law and includes, without limitation, any presence, release, spill, leak, pumping, pouring, addition, emission, emptying, discharge, injection, escape, leaching, disposal, dispersal, migration, dumping, deposit, spraying, burial, abandonment, incineration, seepage or placement;

(dddd) "**Remedial Order**" means any complaint, direction, order or sanction issued, filed or imposed by any Governmental Authority pursuant to any Environmental Law and includes any order requiring any remediation or clean-up of any Hazardous Substance or requiring that any Release or any other activity be reduced, modified or eliminated;

(eeee) "**Remediation**" means restoring the Environment to compliance with Environmental Laws;

(ffff) "**Required Approval**" has the meaning ascribed thereto in Section 7.1;

(gggg) "**Shareholder Declaration**" means the Shareholders' Direction and Unanimous Shareholder Declaration by the Vendor, revised May 12, 2008 and dated May 22, 2008;

(hhhh) "**Tax**" or "**Taxes**" means the PILs and taxes payable pursuant to the EA and all domestic and foreign federal, provincial, state, municipal, territorial or other taxes, imposts, rates, levies, assessments and government fees, charges or dues lawfully levied, assessed or imposed including, without limitation, all income, capital gains, sales, excise, use, property, capital, goods and services, business transfer and value added taxes, all customs and import duties, workers' compensation premiums, Canada Pension Plan premiums, Employment Insurance premiums, and special payments pursuant to Part VI of the EA together with all interest, fines and penalties with respect thereto;

(iiii) "**Tax Return**" means all returns, information returns, declarations, designations, forms, schedules, elections, reports and other documents of every nature whatsoever (including schedules or any related or supporting information) filed or required to be filed with any Governmental Authority with respect to any Taxes, including those required pursuant to Part VI of the EA, or with respect to the administration of any laws, regulations or administrative requirements relating to any Taxes and any amendments thereof;

(jjjj) "**Tax Act**" means the *Income Tax Act* (Canada) and any regulations thereunder;

(kkkk) "**Vendor**" means The Corporation of Haldimand County;

(llll) "**Vendor's Counsel**" means Norton Rose Fulbright Canada LLP;

(mmmm) "**Vendor's Objection**" has the meaning ascribed thereto in Subsection 2.4(b);

(nnnn) "**Working Capital**" means the working capital of the Business. For further clarity, working capital is the amount by which the book value of the current assets of the Business other than cash, differs from the book value of the current liabilities; where the "current assets of the Business" are the sum of the accounts receivable, unbilled revenue, inventories, prepaid expenses, income taxes recoverable by the Business, and other current assets of the Business included in those categories, and the "current liabilities of the Business" are the sum of the accounts payable, accrued liabilities, income taxes payable by the Business, the current portion of customer deposits, advance payments and other current liabilities, but excluding any current liabilities that are included in Net Debt, where all such calculations of working capital will be based upon GAAP and the Financial Statements or Closing Date Financial Statements, as applicable;

(oooo) "**Working Capital Calculation**" means the written statement setting out the detailed calculation of Closing Date Working Capital and the difference between the Closing Date Working Capital and the Working Capital set out in the Financial Statements calculated in accordance with Schedule 2.4;

1.2 **Construction.** This Agreement has been negotiated by each Party with the benefit of legal representation, and any rule of construction to the effect that any ambiguities are to be resolved against the drafting party does not apply to the construction or interpretation of this Agreement.

1.3 **Certain Rules of Interpretation.** In this Agreement:

(a) the division into Articles and Sections and the insertion of headings and the Table of Contents are for convenience of reference only and do not affect the construction or interpretation of this Agreement;

(b) the expressions "hereof", "herein", "hereto", "hereunder", "hereby" and similar expressions refer to this Agreement and not to any particular portion of this Agreement; and

(c) unless specified otherwise or the context otherwise requires:

(i) references to any Article, Section or Schedule are references to the Article or Section of, or Schedule to, this Agreement;

(ii) "including" or "includes" means "including (or includes) but is not limited to" and is not to be construed to limit any general statement preceding it to the specific or similar items or matters immediately following it;

(iii) "the aggregate of", "the total of", "the sum of", or a phrase of similar meaning means "the aggregate (or total or sum), without duplication, of";

(iv) references to Contracts are deemed to include all present amendments, supplements, restatements and replacements to those Contracts as of the date of this Agreement;

(v) references to any legislation, statutory instrument or regulation or a section thereof are references to the legislation, statutory instrument, regulation or section as of the date of this Agreement;

(vi) words in the singular include the plural and vice-versa and words in one gender include all genders.

1.4 **Knowledge.** In this Agreement, any reference to the "knowledge" of any Party means to the best of the knowledge, information and belief of the Party after reviewing all relevant records in their possession or control and making due inquiries regarding the relevant matter, of its relevant representatives, employees, consultants or contractors of the Party and its Affiliates, provided that nothing in this Section 1.4 shall obligate a Party to make inquiries of Persons in non-supervisory roles, except to the extent there are no other relevant Persons of whom to make the relevant inquiry.

1.5 **Performance on Business Days.** If any action is required to be taken pursuant to this Agreement on or by a specified date that is not a Business Day, the action is valid if taken on or by the next succeeding Business Day.

1.6 **Currency.** In this Agreement, references to dollar amounts or "$" are to Canadian dollars.

1.7 **Time of Essence.** Time shall be of the essence in this Agreement.

1.8 **Applicable Law.** This Agreement shall be construed, interpreted and enforced in accordance with, and the respective rights and obligations of the Parties shall be governed by, the laws of the Province of Ontario and the federal laws of Canada applicable therein, and each Party hereby irrevocably and unconditionally attorns to the non-exclusive jurisdiction of the courts of such province and all courts competent to hear appeals therefrom.

1.9 **Successors and Assigns.** This Agreement shall enure to the benefit of and shall be binding on and enforceable by the Parties and their respective successors and permitted assigns. The Purchaser may assign this Agreement in whole or in part to any Affiliate of the Indemnitor on written notice to the Vendor, and may direct a transfer of the shares of HCUI on Closing to one or more such Affiliates; provided, however, that notwithstanding such assignment the Indemnitor and any assignee of the Indemnitor shall be jointly and severally liable for the Purchaser's obligations under this Agreement and provided further that such assignment does not result in the Vendor being subject to any taxes imposed under the EA or any of the Haldimand Corporations being subject to any Taxes to which it or they would not have been subject, but for such assignment.

1.10 **Schedules and Exhibits.** The following Schedules and Exhibits are attached to and form part of this Agreement:

Schedule 2.4	-	Purchase Price Adjustment
Schedule 3.1(l)	-	Real Property
Schedule 3.1(m)	-	Intellectual Property
Schedule 3.1(p)	-	HCUI Employment and Employee Benefit Matters
Schedule 3.1(s)	-	Insurance Policies
Schedule 3.1(u)	-	Vendor Litigation
Schedule 3.1(bb)	-	Licences
Schedule 6.3	-	Community Support
Schedule 6.6	-	Current Rates

ARTICLE II
PURCHASE AND SALE OF PURCHASED SHARES

2.1 **Purchase and Sale of Purchased Shares.** Subject to the terms and conditions hereof, the Vendor agrees to sell, assign and transfer to the Purchaser and the Purchaser, as fully indemnified by the Indemnitor, agrees to purchase from the Vendor all of the issued and outstanding shares of HCUI (the "**Purchased Shares**").

2.2 **Purchase Price.** Subject to those adjustments provided for in Section 2.4, the purchase price payable by the Purchaser to the Vendor for the Purchased Shares shall be the sum of SIXTY-FIVE MILLION, TWO HUNDRED THOUSAND DOLLARS ($65,200,000) (the "**Purchase Price**"), payable as follows:

(a) as to the sum of TWO MILLION, FIVE HUNDRED THOUSAND DOLLARS ($2,500,000.00), by delivery to the Vendor's Counsel, in trust, concurrently with the execution and delivery of this Agreement, of a certified cheque or bank draft payable to the order of the Vendor's Counsel, in trust, as a deposit to be credited to the Purchaser on account of the Purchase Price and, subject to Section 2.3, remitted to the Vendor by Vendor's Counsel on Closing (the "**Deposit**"); and

(b) as to the balance of the Purchase Price (net of accrued interest on the Deposit in accordance with Section 2.3), by the delivery by the Purchaser to the Vendor on Closing of a certified cheque or bank draft payable to the order of the Vendor or other entity as the Vendor may direct.

2.3 **Deposit.** The Deposit shall be held by the Vendor's Counsel, in trust, and shall be invested in an interest bearing account with interest accruing to the Purchaser except as set forth below. On Closing, the Deposit shall be applied on account of the Purchase Price and any and all interest accrued thereon shall be paid to the Purchaser forthwith following Closing.

2.4 **Adjustment to Purchase Price.**

(a) The Purchase Price contemplated in Section 2.2 is based upon:

(i) Net Debt set out in the Closing Date Financial Statements (the "**Closing Date Net Debt**") being equal to the Net Debt set out in the Financial Statements;

(ii) the NFA as set out in or derived from the Closing Date Financial Statements (the "**Closing Date NFA**") being equal to the NFA set out in the Financial Statements; and

(iii) the Working Capital set out in the Closing Date Financial Statements (the "**Closing Date Working Capital**") being equal to the Working Capital set out in the Financial Statements. Within ninety (90) days following the Closing Date, the Vendor shall prepare and deliver to the Purchaser the Closing Date Financial Statements and the audited, unconsolidated statements of HCHI and HCEI, the Net Debt Calculation, the NFA Calculation and the Working Capital Calculation audited by HCUI's external auditors who are to be retained by the Vendor, together with the supporting documentation on which the auditors have relied (in this Section 2.4, the "**Auditors' Supporting Documentation**"); and

(b) Each of the Purchaser and the Vendor shall have a period of thirty (30) Business Days from the latest of the date on which the Closing Date Financial Statements, the Net Debt Calculation, the NFA Calculation, the Working Capital Calculation or the Auditors' Supporting Documentation is received within which to notify the other Party in writing that it disputes any amounts contained in the Closing Date Financial Statements, the Net Debt Calculation, the NFA Calculation or the Working Capital Calculation (the "**Purchaser's Objection**" or "**Vendor's Objection**", as the case may be), failing which the relevant Party not objecting shall be deemed to have accepted the amounts contained in the Closing Date Financial Statements, the Net Debt Calculation, the NFA Calculation and the Working Capital Calculation. Any Purchaser's Objection or Vendor's Objection, shall set forth a detailed description of the basis of the Party's objection and the adjustments to the Closing Date Financial Statements, the Net Debt Calculation, the NFA Calculation or Working Capital Calculation which that Party believes should be made. Any items not specifically disputed during such thirty (30) Business Day period shall be deemed to have been accepted by both Parties.

(c) The Purchase Price shall be adjusted:

(i) on a dollar for dollar basis by:

(1) the difference between the Closing Date Net Debt and the Net Debt in the Financial Statements; and

(2) the difference between the Closing Date Working Capital and the Working Capital derived from the Financial Statements.

(ii) by the product of the NFA Index and the NFA Calculation.

(d) Payment of the net adjustment to the Purchase Price shall be made by the Purchaser or the Vendor (as the case may be) within thirty (30) Business Days of the last date on which to submit a Purchaser's Objection or Vendor's Objection determined in accordance with Subsection 2.4(b);

(e) If the Vendor and the Purchaser cannot settle the Purchaser's Objection or the Vendor's Objection in a timely manner or cannot agree on adjustments to the Purchase Price within the time limit for payment of the adjustments to the Purchase Price pursuant to Section 2.4(d), the Vendor and the Purchaser will submit any unresolved matter within a further five day period, to an independent, nationally recognized accounting firm selected by the Vendor and the Purchaser for resolution in accordance with the *Arbitration Act* (Ontario) or, failing agreement of the Parties on the arbitrator, to a single arbitrator appointed by the Ontario Superior Court of Justice in accordance with the *Arbitration Act* (Ontario) (hereinafter, the "**Arbitrator**"). The Arbitrator will be given access to all materials and information reasonably requested by it for the purpose of resolving unresolved Purchase Price adjustments. The rules and procedures to be followed in the arbitration proceedings will be determined by the Arbitrator in accordance with the *Arbitration Act* (Ontario). The place of the arbitration shall be Toronto, Ontario and the language of the arbitration shall be English. The Arbitrator will make its determination as soon as practicable and, in any case, within thirty (30) days of the matter being submitted to it. The Arbitrator's determination of all such matters will be final and binding on all Parties and will not be subject to appeal by any Party. The fees and expenses of the Arbitrator will be borne equally by the Vendor, on the one hand, and the Purchaser, on the other hand. The draft Closing Date Financial Statements or calculations, as the case may be, will be modified to the extent required to give effect to the Arbitrator's determination and will be deemed to have been approved as of the date of such determination;

(f) Schedule 2.4 is a worksheet setting forth the relevant accounts for adjusting the Purchase Price following Closing. The Parties agree that they have reviewed this worksheet and that to the best of their knowledge it accurately sets forth the Net Debt, the NFA, the Net Regulatory Adjustment and the Working Capital set forth in or derived from the Financial Statements. The external auditors shall be instructed to have regard to the worksheet in calculating Purchase Price adjustments in accordance with Section 2.4(c) and shall only deviate from the worksheet where specifically required under the terms of this Agreement or to correct manifest errors; and

(g) The Parties agree that the Closing Date Financial Statements are to be prepared using GAAP as it existed on December 31, 2013 on a basis consistent with the Financial Statements notwithstanding that HCUI may be using International Financial Reporting Standards on the Closing Date.

2.5 **Rate Reduction Adjustment.**

(a) In the event the OEB does not approve the Negative Rate Rider, the Indemnitor shall pay the Vendor, within five (5) Business Days after the Closing Date, a lump sum amount equal to the Five-Year Fixed Amount in immediately available funds;

(b) In the event the OEB approves the Negative Rate Rider with the Reduced Rate Effective Date occurring after the Closing Date, the Purchaser shall pay the Vendor, within five (5) Business Days after the Closing Date, an amount equal to the product of the Daily Adjustment Value and the Decision Period Days; and

(c) In the event that the OEB approves a Partial Rate Rider and/or the Reduced Rate Effective Date occurs after the Closing Date, the Purchaser will pay the Vendor, within five (5) Business Days after the Closing Date, an amount equal to the product of the Five Year Fixed Amount and the Rate Adjustment Factor, plus the product of the Daily Adjustment Value, the Decision Period Days and the Decision Period Adjustment Factor.

2.6 **Access.** The Purchaser shall provide the Vendor and HCUI's auditors with timely access to all books, records, documents, materials, employees (which access to employees shall include creation of such work product as Vendor may reasonably request) and other information and representatives of the Haldimand Corporations reasonably requested by the Vendor for purposes of preparation and delivery of the Closing Date Financial Statements together with the Net Debt Calculation, Working Capital Calculation, and the NFA Calculation.

ARTICLE III
REPRESENTATIONS AND WARRANTIES

3.1 **Representations and Warranties of the Vendor.** The Vendor represents and warrants to the Purchaser as follows and acknowledges that, except as otherwise expressly provided herein, the Purchaser is relying on such representations and warranties in connection with the transactions contemplated herein:

(a) **Organization.** The Vendor and the Haldimand Corporations are corporations duly incorporated and validly subsisting corporations under the laws of the Province of Ontario and have the corporate power, capacity and authority to own or lease or dispose of their property and assets and to carry on the business presently carried on by them, and the LDC is qualified to carry on the Business under Applicable Law. No proceedings have been instituted or are pending for the dissolution, winding up or liquidation of any of the Haldimand Corporations or the Vendor.

(b) **Corporate Power.** The Vendor has all requisite statutory power, authority and capacity to enter into, and to perform its obligations under this Agreement and any other agreement or document to be delivered pursuant hereto and to transfer the legal and beneficial title and ownership of the Purchased Shares to the Purchaser free and clear of all encumbrances. The Vendor and the Haldimand Corporations have duly taken, or have caused to be taken, all action required to be taken by the Vendor or the Haldimand Corporations to authorize the execution and delivery of this Agreement and any other agreement or document to be delivered pursuant hereto by the Vendor in the performance of its obligations under this Agreement and any other agreement or document to be delivered pursuant hereto.

(c) **Binding Agreement.** This Agreement has been duly executed by the Vendor and will, upon delivery, constitute a valid and binding obligation of the Vendor, enforceable against it in accordance with its terms, except as enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and that equitable remedies may be granted only in the discretion of a court of competent jurisdiction.

(d) **Authorized and Issued Capital.** The authorized share capital of HCUI consists of an unlimited number of Common Shares, of which only 3,001 common shares have been validly allotted and issued and are outstanding as fully paid and non-assessable shares, and will be the only outstanding shares of HCUI at Closing. The authorized share capital of the LDC consists of an unlimited number of common shares, of which only 1,001 common shares have been validly allotted and issued and are outstanding as fully paid and non-assessable shares, and will be the only outstanding shares of the LDC at Closing. The authorized share capital of HCEI consists of an unlimited number of common shares, of which only 1,001 common shares have been validly allotted and issued and are outstanding as fully paid and non-assessable shares, and will be the only outstanding shares of HCEI at Closing.

(e) **Ownership of Purchased Shares.**

(i) The Vendor is the sole beneficial and registered owner of the Purchased Shares, with good and marketable title thereto, free and clear of all encumbrances (other than the rights of the Purchaser hereunder) and has the exclusive right to dispose of the Purchased Shares as herein provided. Without limiting the generality of the foregoing, none of the Purchased Shares is subject to any voting trust, shareholder agreement or voting agreement, except as provided for in the Shareholder Declaration;

(ii) HCUI is the sole beneficial and registered owner of all of the shares of the LDC, with good and marketable title thereto, free and clear of all encumbrances; and

(iii) HCUI is the sole beneficial and registered owner of all of the shares of HCEI, with good and marketable title thereto, free and clear of all encumbrances.

(f) **Options.** No Person (other than the Purchaser under this Agreement) has any Contract or any right or privilege (whether by law, pre-emptive or contractual) binding upon or which any time in the future may become binding upon the Vendor, or any of the Haldimand Corporations to acquire or obtain in any other way an interest in any of the Purchased Shares or the shares of any of the Haldimand Corporations, or obtain in any other way, an interest in any of the Purchased Shares or the shares of any of the Haldimand Corporations.

(g) **Subsidiaries.** Neither the LDC nor HCEI has any subsidiaries or owns, or has any interest in, any shares of any other corporation.

(h) **No Violations.** Neither the execution nor delivery of this Agreement nor the completion of the purchase of the Purchased Shares herein contemplated will result in the violation of:

(i) any provision of the by-laws of the Vendor;

(ii) any Contract to which the Vendor or any of the Haldimand Corporations is a party or by which the Vendor, or any of the Haldimand Corporations or any of their respective properties or assets is bound, which would have a material adverse effect on the Vendor's ability to perform its obligations under this Agreement; or

(iii) subject to obtaining the Required Approval, any terms or provisions of any Applicable Law of any Governmental Authority having jurisdiction over the Vendor or any of the Haldimand Corporations that would have a material adverse effect on the Vendor's ability to perform its obligations under this Agreement.

(i) **Consents and Approvals.** Except for the Required Approval and the filings contemplated in Section 7.2, there is no requirement for the Vendor to make any filing with, give any notice to or obtain any licence, permit, certificate, registration, authorization, consent or approval of, any Governmental Authority as a condition to the lawful consummation of the purchase of the Purchased Shares contemplated by this Agreement.

(j) **Compliance with Law.** The Vendor and each of the Haldimand Corporations have complied in all material respects with all Applicable Laws applicable to each of the Haldimand Corporations and the Business. None of the Haldimand Corporations is in violation or default under, and no event has occurred which, with the lapse of time or the giving of notice or both, would result in the violation of or default under, the terms of any judgment, decree, order injunction or writ of any court or other Governmental Authority.

(k) **Corporate Records.** The corporate records and minute books of all of the Haldimand Corporations are in all material respects a complete and accurate record of the business transacted at meetings of, and contain all resolutions and by-laws passed by, the directors and the sole shareholder of each of the Haldimand Corporations, held since the incorporation of HCUI, HCEI or the LDC, as the case may be, and in all material respects, all such meetings were duly called and held and all such resolutions and by-laws were duly passed. The share certificate book, register of shareholders, register of transfers, register of directors and other corporate registers of each of the Haldimand Corporations are complete and accurate.

(l) **Real Property.**

(i) Schedule 3.1(l) sets forth a list of the real property, other than the Excluded Property, in which any of the Haldimand Corporations has an interest including lands owned in fee simple (the "**Real Property**"), and easements (the "**Easements**"). None of the Haldimand Corporations owns any real property or leases or has agreed to acquire or lease any real property other than as listed in Schedule 3.1(l);

(ii) None of the Haldimand Corporations holds an interest in leased real property;

(iii) Neither the Vendor nor any of the Haldimand Corporations has received, nor to the best of the Vendor's Knowledge are there, any pending or threatened, notices of violation or alleged violation of any Applicable Law or instruction of a Governmental Authority against or affecting any real property owned or occupied by any of the Haldimand Corporations or used in association with the Business, or to the Vendor's knowledge, in respect of any real property previously owned or used in the Business;

(iv) The LDC has such rights of entry and exit to and from Real Property, and Easements as are reasonably necessary to carry on the Business;

(v) No Person other than the LDC is using, possessing or occupying or has any right to use, possess or occupy, any part of the Real Property;

(vi) There exists no option, right of first refusal or other contractual rights with respect to any of the Real Property;

(vii) Neither the Vendor nor any of the Haldimand Corporations has entered into any Contract to sell, transfer, encumber, or otherwise dispose of or impair the right, title and interest of any of the Haldimand Corporations in and to Real Property or the air, density and easement rights relating to such Real Property except as may have been effected by a zoning by-law of general application;

(viii) Neither the Vendor nor any of the Haldimand Corporations has received any notification of, nor are there any outstanding or incomplete work orders in respect of any Fixed Assets or of any current non-compliance (other than non-compliances which are legal non-conforming under relevant zoning by-laws) with applicable statutes and regulations or building and zoning by-laws and regulations;

(ix) Neither the Vendor nor any of the Haldimand Corporations has made an application for a rezoning of any Real Property, and to the Vendor's Knowledge, there is no proposed or pending change to any zoning affecting the Real Property;

(x) No part of the Real Property is subject to any building or use restriction that would prevent or limit its current use in the Business;

(xi) To the Vendor's knowledge, no expropriation or condemnation or similar proceeding is pending or threatened against any part of the Real Property;

(xii) To the Vendor's knowledge, no Fixed Assets constituting a part of the Real Property encroaches on real property not forming part of the Real Property;

(xiii) All accounts falling due on or prior to Closing for work and services performed or materials placed or furnished upon or in respect of the construction and completion of any Fixed Assets of any of the Haldimand Corporations have been fully paid and no Person is entitled to claim a lien under the *Construction Lien Act* (Ontario) or other similar legislation for such work; and

(xiv) There are no matters affecting the right, title and interest of any of the Haldimand Corporations in and to any Real Property or easements that would materially and adversely affect the ability of the LDC to carry on the Business upon such real property.

(m) **Intellectual Property.** Schedule 3.1(m) sets forth and describes all trademarks, trade names, business styles, service marks and brand names used in the Business. The LDC has valid rights to use such intellectual property in the Business.

(n) **Contracts and Commitments.** Except as set forth in the Data Room, none of the Haldimand Corporations is a party to or bound by any of the following:

(i) any employment or consulting Contract or any other Contract with any officer, employee, former employee or consultant other than oral contracts of indefinite hire terminable by the employer without cause on reasonable notice; or

(ii) any Material Contract.

(o) **Material Contracts.** The Data Room contains true and complete copies of all Material Contracts, all of which are in full force and effect and unamended and no material default exists under such Material Contracts on the part of any of the Haldimand Corporations or on the part of any other party to such Material Contracts, and there are no current or pending negotiations with respect to the renewal, repudiation or amendment of any such Material Contracts. The Vendor has delivered to the Purchaser prior to the execution hereof, true and complete copies of all Contracts between the Vendor and any of the Haldimand Corporations.

(p) **Employment and Employee Benefit Matters.**

(i) Except as set forth and described in Schedule 3.1(p), none of the Haldimand Corporations is:

(1) a party to, bound by, subject to and has no liability or contingent liability relating to any employment agreement or any agreement or arrangement relating to Employee Benefits. For greater certainty, none of the

Haldimand Corporations is a party to, bound by or subject to and has no liability or contingent liability under such agreements or arrangement as purchaser or supplier of Employee Benefits;

(2) in arrears in the payment of any contribution or assessment required to be made by it pursuant to any agreements or arrangements relating to Employee Benefits; or

(3) a party to or bound by or subject to any agreement or arrangement with any labour union or employee association or has made any commitment to or conducted any negotiation or discussion with any labour union or employee association in each case with respect to any Employee Benefits.

(ii) All agreements and arrangements set forth in Schedule 3.1(p) (other than OMERS, with respect to which the Vendor makes no representation) are, and have been, established, registered (where required), and administered without default, in material compliance with:

(1) the terms thereof;

(2) all Applicable Laws; and

(3) any applicable collective agreements; and neither the Vendor nor any of the Haldimand Corporations has received, in the last four (4) years, any notice from any Person questioning or challenging such compliance (other than in respect of any claim related solely to that Person), nor to the Vendor's Knowledge has any Person given notice questioning or challenging such compliance beyond the last four (4) years. Except as disclosed in Schedule 3.1(p), there are no promised improvements, increases or changes to, such agreements or the benefits provided under any such agreement or arrangement, nor does any such agreement or arrangement provide for benefit increases or the acceleration of funding obligations that are contingent upon or will be triggered by the execution of this Agreement or the Closing. Neither HCUI nor HCEI participates or has ever participated in OMERS;

(iii) Except as disclosed in Schedule 3.1(p), no agreement or arrangement relating to Employee Benefits, other than OMERS, provides benefits beyond retirement or other termination of service to employees or former employees of any of the Haldimand Corporations or to the beneficiaries or dependants of such employees or former employees. Other than OMERS, no such agreement or arrangement requires or permits a retroactive increase in premiums or payments;

(iv) Except as disclosed on Schedule 3.1(p), no Employee is on long-term disability leave, extended absence or receiving benefits pursuant to the *Workplace Safety and Insurance Act* (Ontario);

(v) All assessments under the *Workplace Safety and Insurance Act* (Ontario) in relation to the Business have been paid or accrued and none of the Haldimand Corporations is subject to any special or penalty assessment under such legislation that has not been paid;

(vi) There is no strike or lockout occurring or affecting, or to the Vendor's knowledge threatened against any of the Haldimand Corporations; and

(vii) Each of the Haldimand Corporations has been operated in material compliance with all laws relating to employees, including employment standards and all laws relating in full or in part to the protection of employee health and safety, human rights, labour relations and pay equity. There have been no Claims nor, to the best of the Vendor's knowledge, are there any threatened complaints, under such laws against any of the Haldimand Corporations. To the Vendor's knowledge, nothing has occurred which might lead to a Claim or complaint against any of the Haldimand Corporations, under any such law. There are no outstanding decisions or settlements or pending settlements which place any obligation upon any of the Haldimand Corporations to do or refrain from doing any act.

(q) **Employees.** As of the date of this Agreement, neither HCUI nor HCEI has any employees and the LDC has a total of 52 full time and no part-time employees, of whom approximately 36 employees are represented by the Independent Brotherhood of Electrical Workers union. Vendor has delivered to the Purchaser a document which contains a complete and accurate list of the names of all individuals who are employees (the "**Employees**") of the LDC specifying title, years of service and Employee Benefits to which they are entitled, and which Vendor will update prior to and as of Closing.

(r) **Pension and Retirement Plans.**

(i) OMERS is the only pension or retirement plan or arrangement in which employees or former employees of any of the Haldimand Corporations participate and/or to which any of the Haldimand Corporations contribute as a participating employer;

(ii) All obligations of the LDC to or under OMERS (whether pursuant to the terms thereof or Applicable Laws) have been satisfied and there are no outstanding defaults or violations thereunder by the LDC or by any predecessor thereof;

(iii) The Haldimand Corporations have no outstanding obligations with respect to unfunded actuarial liabilities, past service unfunded liabilities or solvency deficiencies respecting the LDC's participation in OMERS;

(iv) All employee data necessary to administer the LDC's participation in OMERS and any other agreement or arrangement listed in Data Room is in the possession of the LDC and is complete, correct and in a form which is sufficient for the proper administration of the LDC's participation in OMERS and any other agreement listed in Schedule 3.1(p) in accordance with the terms thereof and Applicable Laws; and

(v) All employer or employee payments, contributions or premiums required to be remitted, paid by the LDC to or in respect of OMERS have been paid or remitted in a timely fashion in accordance with the terms thereof and Applicable Law, and no Taxes, penalties or fees are owing or exigible on the LDC under OMERS.

(s) **Insurance.** Schedule 3.1(s) sets forth all insurance policies (specifying the insurer, the amount of the coverage, the type of insurance, the policy number and any pending claims thereunder) maintained by the Vendor or any of the Haldimand Corporations on Property or personnel (including former personnel) of the Business.

(t) **Environmental Matters.** Except as set out in a Confidential Disclosure Schedule provided by Vendor to Purchaser prior to execution hereof,

(i) the Business and Property have been and are being owned, occupied and operated in substantial compliance with applicable Environmental Laws and there are no breaches thereof and no enforcement actions in respect thereof. No Release, spill, leak, emission, discharge, leaching, dumping or disposal of Hazardous Substances has occurred on or from any Real Property, except those that do not violate applicable Environmental Laws and, there has been no Release by any of the Haldimand Corporations which is now present in, on or under any of the Property or to the Vendor's knowledge any neighbouring or adjoining property (including, without limitation, underlying soils and substrata, surface water, ground water and vegetation) at levels which exceed decommissioning or remediation standards under any applicable Environmental Laws;

(ii) All of the Haldimand Corporations have obtained all requisite Environmental Approvals, which Environmental Approvals are valid and in full force and effect, have been and are being complied with in all material respects and there have been and are no proceedings commenced or threatened to revoke or amend any Environmental Approvals in a manner that could reasonably be expected to have a Material Adverse Effect;

(iii) none of the Haldimand Corporations has been or is now the subject of any Remedial Order nor, is any investigation or evaluation threatened or commenced as to whether any such Remedial Order is necessary;

(iv) none of the Haldimand Corporations has ever been prosecuted for or convicted of any offence under Environmental Laws, nor have any of the Haldimand Corporations been found liable in any proceeding to pay any Damages, fine or judgment to any Person as a result of any Release or threatened Release of any Hazardous Substance into the Environment or as the result of any breach of any Environmental Law. No notice has been received by the Vendor, or any of the Haldimand Corporations of any investigation or evaluation by any Governmental Authority or of any Claims, pending or threatened, and there are no investigations or evaluations threatened or commenced as to whether any offence by any of the Haldimand Corporations has occurred under Environmental Law. There are no Claims or proceedings of any nature or kind that have been threatened or commenced against any of the Haldimand Corporations as a result of any Release or threatened Release of any Hazardous Substance into the Environment or as the result of the breach of any Environmental Laws;

(v) no part of the Real Property has ever been used as a landfill or for the disposal of waste;

(vi) no asbestos, asbestos containing materials, polychlorinated biphenyls ("**PCBs**") and PCB wastes are used, stored or otherwise present in or on the Real Property except for PCBs contained in the electrical transformers which are in service and which form an integral part of, and are necessary for the operation of the Business. The Vendor has disclosed to the Purchaser all inspection reports received from the Ministry of the Environment in connection with any of the Haldimand Corporations' handling, transportation and storage of PCBs; and

(vii) there are no Hazardous Substances in, on or under the real property owned or occupied by the LDC, used in the Business or concerning the condition of which the LDC is otherwise responsible and there are no underground storage tanks on the Real Property and any underground storage tanks formerly on property owned or occupied by the LDC have been removed and any affected soil, surface water or ground water has been remediated in compliance with all Applicable Law including, without limitation, Environmental Law.

(u) **Litigation.** Except as set out in Schedule 3.1(u), there are no Claims in progress (whether or not purportedly on behalf of the LDC) pending or, to the Vendor's Knowledge, threatened against or affecting, any of the Haldimand Corporations at law or in equity, or before or by any federal, provincial, municipal or other governmental department, court, commission, board, bureau, agency or instrumentality, domestic or foreign, or by or before an arbitrator or arbitration board which, either individually or in the aggregate, would have a Material Adverse Effect or prevent the Vendor or any of the Haldimand Corporations from fulfilling any of its respective obligations set out in, or arising in connection with, this Agreement or any other agreement or document to be delivered pursuant hereto.

(v) **Taxes.**

(i) The Vendor is not a non-resident of Canada for the purposes of the Tax Act or equivalent legislation;

(ii) Each of the Haldimand Corporations is exempt from tax under the Tax Act and the CTA but is required to make PILs payments under the EA in an amount equal to the tax that it would be liable to pay under the Tax Act and CTA if it were not exempt from tax under those statutes;

(iii) Each of the Haldimand Corporations have filed in the prescribed manner and within the prescribed times all Tax Returns required to be filed by it in all applicable jurisdictions with respect to taxation period ended on or before the Closing Date. All such Tax Returns are complete and correct and disclose all Taxes required to be paid for the periods covered thereby and no material fact has been omitted therefrom. The Haldimand Corporations have never been required to file any Tax Returns with, and have never been liable to pay or remit Taxes to, any Governmental Authority outside Ontario or Canada. The Haldimand Corporations have paid in full and when due all Taxes and all instalments of Taxes due on or before the Closing Date. There are no liens for unpaid Taxes on any of the Haldimand Corporations' assets. Without restricting the generality of the foregoing, all Taxes shown on all Tax Returns or on any assessments or reassessments in respect of any such Tax Returns have been paid in full when due. The Vendor has furnished to the Purchaser true, complete and accurate copies of all Tax Returns and any amendments thereto filed by the Haldimand Corporations since December 31, 2008 and all notices of assessment and reassessment and all correspondence with Governmental Authorities relating thereto as well as true, complete and accurate copies of all Tax Returns and any amendments filed at any time with respect to a taxation year that is not statute barred, and all notices of assessment and reassessment and all correspondence with Governmental Authorities or tax advisors relating thereto. The provision for Taxes in the Financial Statements constitutes an adequate provision for the payment of all unpaid Taxes in respect of all periods up to and including the period to which the Financial Statements relate;

(iv) Assessments under the EA will have been issued to the Haldimand Corporations and disclosed to the Purchaser covering all periods up to and including its fiscal year ended immediately prior to Closing;

(v) There are no audits, assessments, reassessments or other Claims in progress or, to the knowledge of the Vendor, threatened against any of the Haldimand

Corporations, in respect of any Taxes and, in particular, there are no currently outstanding reassessments or written enquiries which have been issued or raised by any Governmental Authority relating to any such Taxes. The Vendor is not aware of any contingent liability of any of the Haldimand Corporations for Taxes or any grounds that could prompt an assessment or reassessment for Taxes, and the Haldimand Corporations have not received any indication from any Governmental Authority that any assessment or reassessment is proposed in respect of taxation periods ended on or before Closing;

(vi) None of the Haldimand Corporations has entered into any transactions with any non-resident of Canada (for the purposes of the Tax Act) with which such Haldimand Corporation was not dealing at arm's length (within the meaning of the Tax Act). None of the Haldimand Corporations has acquired property from any Person in circumstances where such Haldimand Corporations was or could have become liable for any Taxes payable by that Person;

(vii) None of the Haldimand Corporations has entered into any agreements, waivers or other arrangements with any Governmental Authority providing for an extension of time with respect to the issuance of any assessment or reassessment, the filing of any Tax Return, or the payment of any Taxes by or in respect of any of the Haldimand Corporations. None of the Haldimand Corporations is party to any agreements or undertakings with respect to Taxes;

(viii) Each of the Haldimand Corporations is duly registered under the ETA and under applicable provincial Tax statutes in respect of all provincial Taxes which it is or has been required to collect and their respective HST registration numbers are as follows:

[redacted] [redacted]

All input tax credits claimed by the Haldimand Corporations pursuant to the ETA have been proper, correctly calculated and documented in accordance with the requirements of the ETA and the regulations thereto. Each of the Haldimand Corporations have collected, paid and remitted when due all Taxes, including GST/HST and RST, collectible, payable or remittable prior to the Closing Date, as required by tax legislation.

(ix) Each of the Haldimand Corporations maintains its respective books and records in compliance with section 230 of the Tax Act;

(x) To the best of Vendor's knowledge, Vendor has provided to the Purchaser true, complete and accurate copies of all Canadian federal and Ontario income Tax Returns of each of the Haldimand Corporations for the last four (4) completed taxation years and all related communications to or from all Governmental Authorities, including all assessments issued by Governmental Authorities (if any) in respect of such Tax Returns received by the Haldimand Corporations prior to or on the Closing Date. Canadian federal and provincial income, sales (including goods and services and harmonized sales and provincial or territorial sales) and capital tax assessments have been issued to each of the Haldimand Corporations for all taxation years or periods up to and including its taxation year ended as of Closing Date. No notices of determination of loss from the Canada Revenue Agency for any of the Haldimand Corporations have been requested by or issued to any of the Haldimand Corporations;

(xi) None of the Haldimand corporations has requested, received or entered into any advance Tax rulings or advance pricing agreements with any Governmental Authority;

(xii) None of the Haldimand Corporations is a party to, or bound by or obligated by contract or otherwise, any undertaking regarding any Tax allocation, indemnity or sharing contract or arrangement, and neither is liable for the Taxes of any other Person as a transferee or successor;

(xiii) The value of consideration paid or received by each of the Haldimand Corporations for the acquisition, sale, transfer or provision of property (including intangibles) or the provision of services (including financial transactions) from or to any Person with which it was not dealing at arm's length at the relevant time was compliant with the provisions of the Affiliate Relationships Code under the OEB Act;

(xiv) The cost amount, as defined in the Tax Act, of the assets of each of the Haldimand Corporations is accurately reflected where required on such corporation's Tax Returns and has not materially and adversely changed since the date of such Tax Returns; and

(xv) No Claim has ever been made by a taxing authority, in a jurisdiction where any of the Haldimand Corporations does not file Tax Returns, that such Haldimand Corporation is or may be subject to taxation by that jurisdiction or that any of the assets of such Haldimand Corporation are or may be subject to such taxation.

(w) **Withholding.** Each of the Haldimand Corporations has deducted, withheld, collected and remitted when due to each Governmental Authority, all Taxes which either is required to deduct, withhold, collect and remit. Without restricting the generality of the foregoing, each of the Haldimand Corporations has withheld from each amount paid or credited or deemed to have been paid or credited, and each taxable benefit conferred upon or dividend or distribution paid or deemed to have been paid to any of its past or present employees, shareholders officers or directors, and to any non-resident of Canada within the meaning of the Tax Act, the amount of all Taxes and other deductions required to be withheld therefrom by Applicable Law, including without limitation, all employee and employer portions for Workers' Compensation, Canada Pension Plan, Employer Health Tax and Employment Insurance and has paid the same to the proper Governmental Authority within the time required under any Applicable Law. Each of the Haldimand Corporations has remitted to the appropriate Governmental Authority when required by law to do so all amounts collected by it on account of sales taxes including HST. None of the Haldimand Corporations has received any requirement, demand or request from any Governmental Authority pursuant to section 224 of the Tax Act or any similar provision of an Applicable Law that remains unsatisfied in any respect.

(x) **Tax Elections.** None of the Haldimand Corporations has filed or been party to any election, designation or similar filing relating to Taxes.

(y) **Ownership of Property.** The LDC is the sole beneficial and (where its interests are registrable) the sole registered owner of all of the Property used in connection with, directly or indirectly, ancillary to, or reasonably necessary for the operation of the Business with good and valid title thereto free and clear of all encumbrances other than in respect of the Real Property, minor encumbrances for the supply of utilities to such property. All of the Fixed Assets used in connection with, directly or indirectly, ancillary to, or reasonably necessary for the operation of the Business are, except to the extent detailed in the Haldimand County Hydro Asset Condition Assessment dated

September 12, 2013 prepared by Kinetrics or the 2014 cost-of-service application, in good working order, condition and repair, have been properly and regularly maintained and are free of any structural defect and free from any defect in material and workmanship, are of merchantable quality and fit for the purposes of the Business and are in material compliance with all Applicable Laws. There has been no assignment, subletting or granting of any licence (of occupation or otherwise) of or in respect of any such Property or any granting of any Contract or right capable of becoming a Contract or option for the purchase of any of such Property other than pursuant to the provisions of, or as disclosed in, this Agreement.

(z) **Financial Statements.** The Financial Statements were prepared, subject to Section 2.4(g), in accordance with GAAP applied on a basis consistent with that of the preceding period and present fairly all of the assets, liabilities and financial position of each of the Haldimand Corporations on a consolidated basis as at December 31, 2013, and the sales, earnings, results of operation and changes in financial position of the Haldimand Corporations on a consolidated basis for the twelve-month period then ended.

(aa) **By-Laws.** Other than by-laws of general application, no by-law of the Municipality exists which materially adversely affects any of the Haldimand Corporations or the Business. Other than by-laws of general application, no by-law that would materially adversely affect any of the Haldimand Corporations or the Business is currently being contemplated by the Vendor or, to the Vendor's knowledge, has been proposed by any Person.

(bb) **Licences.** Schedule 3.1(bb) sets out a complete list of all licences, permits, approvals, consents, certificates, registrations and authorizations other than off-the-shelf shrink-wrapped software licences ("**Licences**") held by or granted to any of the Haldimand Corporations, and there are no other licences, permits, approvals, consents, certificates, registrations or authorizations necessary to carry on the Business other than the Required Approvals. Each Licence is valid, subsisting and in good standing and none of the Haldimand Corporations is in default or breach of any Licence and, to the best of the Vendor's Knowledge, no proceeding is threatened or pending to revoke or limit any Licence.

(cc) **Bank Accounts.** Vendor shall deliver to Purchaser prior to closing, a complete list of every financial institution in which any of the Haldimand Corporations maintains any depository account, trust account or safety deposit box and the names of all Persons authorized to draw on or who have access to such accounts or safety deposit box.

(dd) **Subsidiaries.** The LDC and HCEI are the only subsidiaries of HCUI and neither HCUI, HCEI nor the LDC owns or has any interest in any shares of any other corporation except for Haldimand County Generation Inc., which will be dissolved as provided in Section 5.9. Haldimand County Generation Inc. has never been used in any transaction by the Vendor or any of the Haldimand Corporations.

(ee) **Absence of Guarantees.** None of the Haldimand Corporations has given or agreed to give, nor is it a party or bound by, any guarantee or indemnity in respect of indebtedness, or other obligations, of any Person, or any other commitment by which any of the Haldimand Corporations is, or is contingently, responsible for such indebtedness or other obligations.

(ff) **Limitation.** The Vendor makes no representation or warranty to the Purchaser except as specifically set forth in this Section 3.1 and this Agreement contains all representations and warranties of the Vendor relating to the purchase of the Purchased Shares contemplated hereby.

(gg) **Effect of Disclosure.** All disclosure contained in a particular representation and warranty set forth in this Agreement (or any Schedule referred to therein) shall be deemed for the purposes of this Agreement to have been made with respect to all of the representations and warranties in this Section 3.1 to which such disclosure might be applicable. Notwithstanding anything else contained herein, the Vendor shall have no liability to the Purchaser with respect to any failure by it to disclose the existence of any matter, document or thing, or to make any other disclosure in the context of a particular representation and warranty set out in this Section 3.1 where the existence of such matter, document or thing has been disclosed as part of another representation or warranty contained in this Agreement or in any Schedule annexed hereto.

3.2 **Representations and Warranties of the Purchaser and the Indemnitor.** The Purchaser and the Indemnitor each jointly and severally represent and warrant to the Vendor as follows and acknowledges that the Vendor is relying on such representations and warranties in order to enter into the transactions contemplated herein:

(a) **Organization.** It is a corporation duly incorporated and validly subsisting corporation under the laws of Ontario and has the corporate power to own or lease its property and assets and to carry on the business presently carried on by it.

(b) **Corporate Power and Due Authorization.** It has all requisite corporate power, authority and capacity to enter into, and to perform its obligations under this Agreement and any other agreement or document to be delivered pursuant hereto. It has duly taken, or has caused to be taken, all corporate action required to be taken by it to authorize the execution and delivery of this Agreement and any other agreement or document to be delivered pursuant hereto by it in the performance of its obligations hereunder and has the financial ability to complete the Purchase and pay the Purchase Price.

(c) **Binding Agreement.** This Agreement has been duly executed by it and will, upon delivery, constitute a valid and binding obligation of the Purchaser and the Indemnitor enforceable against it in accordance with its terms, except as enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction.

(d) **No Violations.** Neither the execution nor delivery of this Agreement nor the completion of the purchase of the Purchased Shares herein contemplated will result in the violation of:

(i) any provision of the constating documents, by-laws or any unanimous shareholder agreement of the Purchaser or Indemnitor;

(ii) any Contract to which it is a party or by which it, or any of its property or assets is bound, which would have a material adverse effect on the its ability to perform its obligations under this Agreement; or

(iii) subject to obtaining the Required Approval,, any terms or provisions of any Applicable Law of any authority having jurisdiction over the Purchaser or the Indemnitor, which would have a material adverse effect on its ability to perform its obligations under this Agreement.

(e) **Investment Canada Act.** It is not a "non-Canadian" within the meaning of the *Investment Canada Act* (Canada).

(f) **Consents and Approvals.** Except as set out in Article VII, there is no requirement for it to make any filing with, give any notice to or obtain any licence, permit, certificate, registration, authorization, consent or approval of, any Governmental Authority as a condition to the lawful consummation of the transactions contemplated by this Agreement.

(g) **Litigation.** There are no Claims in progress, pending, or, to the Purchaser's and Indemnitor's Knowledge, threatened against or affecting the Purchaser at law or in equity, or before or by any federal, provincial, municipal or other governmental department, court, commission, board, bureau, agency or instrumentality, domestic or foreign, or by or before an arbitrator or arbitration board which, either individually or in the aggregate, would have a material adverse effect or prevent it from fulfilling any of its obligations set out in, or arising in connection with, this Agreement or any other agreement or document to be delivered pursuant hereto.

(h) **Limitation.** The Purchaser makes no representation or warranty to the Vendor except as specifically set forth in this Section 3.2 and this Agreement contains all representations and warranties of the Purchaser relating to the purchase of the Purchased Shares contemplated hereby.

(i) **Effect of Disclosure.** All disclosure contained in a particular representation and warranty set forth in this Agreement (or any Schedule referred to therein) shall be deemed for the purposes of this Agreement to have been made with respect to all of the representations and warranties in this Section 3.2 to which such disclosure might be applicable. Notwithstanding anything else contained herein, the Purchaser shall not have any liability to the Vendor with respect to any failure by it to disclose the existence of any matter, document or thing, or to make any other disclosure in the context of a particular representation and warranty set out in this Section 3.2 where the existence of such matter, document or thing has been disclosed as part of another representation or warranty contained in this Agreement or in any Schedule annexed hereto.

(j) **Transfer Tax.** As of the date of execution of this Agreement, Purchaser is exempt pursuant to s. 149(1) of the Tax Act and its equivalent provision under the CTA, and Purchaser is a subsidiary of the Indemnitor for the purposes of s. 94 of the EA and Purchaser and Indemnitor will take no actions to make this representation untrue on Closing.

ARTICLE IV
SURVIVAL OF REPRESENTATIONS AND WARRANTIES

4.1 Survival of Representation and Warranties.

(a) The representations and warranties of the Vendor set out in Section 3.1 and the obligation of indemnity contained in Subsection 11.1(a)(ii) shall survive the Closing and, notwithstanding such Closing or any investigation made by or on behalf of the Purchaser with respect thereto, shall continue in full force and effect for the benefit of the Purchaser provided, however, no Claim in respect thereof shall be valid unless such Claim is made within a period of two (2) years from the date of discovery. Upon the expiry of such limitation period, the Vendor shall have no further liability to the Purchaser with respect to the representations and warranties referred to in such section, except in respect of valid Claims that have been made by the Purchaser to the Vendor in writing prior to the expiration of such limitation period.

(b) The representations and warranties of the Purchaser and the Indemnitor set out in Section 3.2 shall survive the Closing and, notwithstanding such Closing or any investigation made by or on behalf of the Vendor with respect thereto, shall continue in full force and effect for the benefit of the Vendor provided, however, that no Claim in respect thereof shall be valid unless it is made within a period of two (2) years from the date of discovery and, upon the expiry of such limitation period, the Purchaser shall have no further liability to the Vendor with respect to the representations and warranties referred to in such section, except in respect of Claims which have been made by the Vendor to the Purchaser in writing prior to the expiration of such period.

ARTICLE V
COVENANTS OF THE VENDOR

5.1 **Access to the Haldimand Corporations.** The Vendor shall forthwith make available to the Purchaser and its authorized representatives and, if requested in writing by the Purchaser, provide a copy to the Purchaser of, all title documents, Contracts, financial statements, policies, plans, reports, licences, orders, permits, books of account, accounting records and all other documents, information and data relating to the Business of any of the Haldimand Corporations and the business of Haldimand County Generation Inc. The Vendor shall afford the Purchaser and its authorized representatives every reasonable opportunity to have free and unrestricted access to the Business and the Property, assets and records of each of the Haldimand Corporations. At the request of the Purchaser, the Vendor shall execute, or shall cause each of the Haldimand Corporations to execute, such consents, authorizations and directions as may be necessary to permit any inspection of the Business or to enable the Purchaser or its authorized representatives to obtain full access to all files and records relating to any of the Business maintained by governmental or other public authorities. The Vendor and the Purchaser shall co-operate in good faith in arranging any such meetings as the Purchaser should reasonably request with:

(a) Employees of the Vendor or elected officials active in the Business, provided that to the extent that the Purchaser requests a meeting with a specific Employee for the purposes of conducting due diligence or preparing for operation of the LDC, the Vendor may substitute a meeting with a more senior Employee if the Vendor reasonably believes such senior Employee has more in-depth knowledge pertaining to the subject area of Purchaser's inquiry;

(b) suppliers, distributors, service providers or others who have a business relationship with the Vendor, or any of the Haldimand Corporations in respect of the Business; and

(c) the exercise of any rights of inspection by or on behalf of the Purchaser under this Section 5.1 shall not mitigate or otherwise affect any of the representations and warranties of the Vendor hereunder, which shall continue in full force and effect as provided in Section 4.1.

5.2 **Conduct of Business Prior to Closing.** During the Interim Period, none of the Haldimand Corporations has sold or otherwise disposed of any of its Property (other than sales or dispositions of Property in the ordinary course) and the Vendor has not sold or otherwise disposed of any of its property used in connection with the Business. During such period there has been no change in the Business or in the operations, affairs, personnel or financial condition of the Business or of any of the Haldimand Corporations (except, with respect to the LDC only, for changes occurring in the ordinary course of business which, in the aggregate, have not had a Material Adverse Effect), and none of the Haldimand Corporations has authorized, agreed or otherwise become committed to do any of the foregoing. The Vendor shall cause the Business to be conducted in the ordinary course substantially consistent with past practice (except as may be otherwise required or contemplated by the provisions of this Agreement), during the Interim Period. During the Interim Period, Vendor shall cause the LDC to transfer the Excluded Property to the Vendor, at book value. Purchaser expressly acknowledges that HCHI may acquire short-term debt in the amount of up to $7.5M within the Interim Period in the form of variable-rate, demand loans, re-payable without penalty on or after Closing. The Parties acknowledge that, notwithstanding anything herein contained to the contrary, during the Interim Period, the Haldimand Corporations shall be permitted to declare and pay dividends to their respective shareholders out of cash on hand.

5.3 **Delivery of Books and Records.** At Closing, the Vendor shall cause to be delivered to the Purchaser all of the books and records of and relating to any of the Haldimand Corporations and the Business, provided that Vendor shall be entitled to retain copies of any such books and records provided that such books and records are reasonably required by the Vendor to perform its obligations hereunder or under Applicable Law.

5.4 **Resignation of Directors and Officers.** The Vendor shall cause all of the directors and officers of each of the Haldimand Corporations to resign their corporate offices (but not their employment) in favour of nominees of the Purchaser, such resignation to be effective at Closing.

5.5 **No Material Contracts.** From and after the date hereof, none of the Haldimand Corporations shall enter into any Material Contracts without the prior consent of the Purchaser, which consent may not be unreasonably delayed but may be unreasonably withheld. No consent shall be required for any Material Contract contemplated in an approved budget with a completion date on or prior to May 31, 2015. Notwithstanding the forgoing and in any event, a Haldimand Corporation may enter into any of the following commitments, on expiry and not in advance, provided doing so is in the ordinary course of its Business and in accordance with past practice: renew MEARIE property and liability policy for the minimum period permitted, not to exceed three (3) years; renew annual liability insurance effected through Frank Cowan, renew annual software maintenance or support contracts; and renew the annual industry association memberships referenced in Schedule 3.1(s).

5.6 **Non-Assignable Assets.** The Vendor will use its best efforts to obtain any consents required from third parties to the effective transfer of the Property to and for the enjoyment of HCUI, HCEI or the LDC as the case may be and in the absence of any such consent or effective transfer, Vendor shall hold such asset in trust for the benefit of such of HCUI, HCEI or the LDC as the Purchaser may request, in connection with which trust Indemnitor shall indemnify Vendor. As Purchaser intends to pay off all third-party debt identified in the Financial Statements immediately following Closing, Vendor is not obligated to obtain consents to change of control even if required by the terms of such debt.

5.7 **Transfer of Purchased Shares.** The Vendor shall take, and shall cause HCUI to take, all necessary steps and proceedings to permit the Purchased Shares to be duly and validly transferred to the Purchaser and to have such transfers duly and validly recorded on the books of HCUI so that the Purchaser is entered onto the books of HCUI as the holder of the Purchased Shares and to issue share certificates to the Purchaser representing the Purchased Shares effective on Closing.

5.8 **Best Efforts.** The Vendor shall use its best efforts (which shall not be less than commercially reasonable efforts) to cause each of the conditions set forth in Section 9.1 to be performed at or prior to Closing.

5.9 **Dissolution of Generation Subsidiary.** The Vendor shall cause HCUI to discharge all liabilities of Haldimand County Generation Inc. and dissolve Haldimand County Generation Inc. prior to Closing.

5.10 **Restriction on Transfers.** The Vendor covenants and agrees that, between the date of this Agreement and Closing, the Vendor shall not, and shall cause its subsidiaries to not, transfer or acquire any property unless it is property acquired from, or transferred to, a Person dealing at arm's length with the Vendor and its subsidiaries in the ordinary course of business.

5.11 **Remediation of Environment.** The Vendor shall specifically indemnify the Purchaser with respect to the costs of Remediation of any breach of Environmental Laws associated with the Real Property, which the LDC has not brought into compliance with Environmental Law on or before Closing, having regard to the use of the Real Property and neighbouring properties, whether or not such Remediation incidentally improves conditions arising in connection with operation of the Business following Closing. Except to the extent of such incidental improvements, Vendor shall not be liable to indemnify Purchaser or Indemnitor for any such costs of Remediation that resulted from the actions or negligence of the Purchaser or Indemnitor with respect to non-compliance with Environmental Laws in relation to the Real Properties after the Closing Date. The Purchaser agrees to promptly notify the Vendor of its intention to undertake any such Remediation and shall provide the Vendor with the opportunity to comment on the Purchaser's proposed Remediation plan, which comments the Purchaser agrees to reasonably consider. The Purchaser further agrees that in preparation or execution of such plan, Purchaser will not discriminate (in the manner or extent of the Remediation), between the Real Property and other property in Hydro One Network Inc.'s ratebase.

5.12 **Financial Statements.** The Vendor shall cause the Closing Date Financial Statements, subject to Section 2.4(g), to be prepared in accordance with GAAP applied on a basis consistent with that of the preceding period and present fairly the assets and liabilities of the Haldimand Corporations on a consolidated basis as at Closing.

ARTICLE VI
COVENANTS OF THE PURCHASER AND INDEMNITOR

6.1 **Employment and Location Guarantees.** The Purchaser hereby covenants and agrees that for a period of 1 year following the integration of the Business of the LDC with Hydro One Networks Inc., Purchaser will guarantee the continued employment within the Municipality with the LDC, the Purchaser, Indemnitor, or an Affiliate of the Purchaser or Indemnitor, of each Employee who is an active Employee of the LDC on the Closing Date on terms and conditions, including Employee Benefits calculated on the same basis as provided to Hydro One Networks Inc. employees hired on the Closing Date, except that past service with the LDC and related expertise, will be recognized as service with Hydro One Networks Inc. where possible for seniority purposes, and the Purchaser will not, during such period, terminate the employment of any such Employee, except for just cause. The foregoing shall not prohibit the relocation of Employees with their prior consent. From and after the integration of the Business of the LDC with Hydro One Networks Inc., Employees may apply for positions within the Purchaser, Indemnitor and/or their Affiliates and will be considered for such positions on a fair and equal basis with other employees of the Purchaser, Indemnitor and their Affiliates with credit for their seniority and service, as applicable under the applicable employer's collective agreements. Purchaser intends to complete integration of the LDC within twelve to eighteen months of the Closing Date.

6.2 **Local Presence.** The Purchaser and Indemnitor will cause Hydro One Networks Inc. to relocate certain field operations and other work being performed from its Lincoln and Dundas Operations Centre to new or existing facilities in the Municipality. At a minimum, the quantity of work so relocated shall be equivalent to that currently being performed by 30 full time equivalent employees. In evaluating potential sites for such facilities, Purchaser agrees to consider in good faith, locating first, in the Frank A Marshall Business Park or otherwise in Dunnville. If Purchaser selects an available site within the said business park, Vendor agrees to sell the lands to Purchaser at fair market value.

6.3 **Community Support.** After Closing, the Employees and the Municipality shall be eligible for all programs and benefits provided by Purchaser on an equal basis with all other employees and communities served by Purchaser and the programs and benefits referenced in Schedule 6.3.

6.4 **Advisory Committee.** The Purchaser shall establish an advisory committee (the "**Advisory Committee**") as soon as practicable after Closing, in order to provide a forum for communication between the Purchaser and the Vendor. In establishing the Advisory Committee, the Purchaser shall select representatives, including the local superintendent from Hydro One Network Inc.'s Zone 2 or equivalent, in consultation with officials of the Vendor. The Vendor may appoint at least three representatives to the Advisory Committee.

6.5 **Reliability of Power.** If at any time during the period beginning on the Closing Date and continuing for the five (5) years following Closing Date, the five-year rolling average for reliability (as measured by the system average interruption duration index) in the LDC's pre-closing territory as measured by Purchaser and reported to Vendor, falls below the average reliability reported by the LDC to the OEB for the five (5) years prior to Closing, Purchaser shall make a payment to the Vendor in the amount of $100,000 to be used to address charitable or other community interests.

6.6 **Rate Certainty.** The LDC's 2014 base rates approved by the OEB (the "**Current Rates**"), are set out in Schedule 6.6.

The Purchaser and Indemnitor jointly and severally acknowledge, agree and covenant to:

(a) within the timeframe specified in Section 7.1 and as part of, or contemporaneous with, the Required Approval, apply for OEB Approval for a negative rate rider to reduce Current Rates by one percent (1%) across all Rate classes("**Negative Rate Rider**");

(b) take all reasonable steps to ensure that the Current Rates less the Negative Rate Rider to the extent approved by the OEB (the "**Reduced Rates**") shall:

(i) be effective as of the Closing Date or such other date stipulated by the OEB; and

(ii) be maintained without change during the Rate Freeze Period; and

(c) following the Rate Freeze Period and subject to the proviso that materially similar business and regulatory conditions continue, pursue a distinct class of rates for similarly-situated, newly acquired territories recognizing their higher-than-average customer base density and lower-than-average cost-to-serve.

6.7 **Employee-Related Matters.** The Purchaser and Indemnitor acknowledge that from and after the Closing Date, the LDC shall be responsible for all obligations owing to present and former employees and beneficiaries of the LDC relating to such employment, including, but not limited to, all obligations and liabilities relating to wages, severance pay, notice of termination of employment or pay in lieu of such notice, Damages for wrongful dismissal or other employee benefits or Claims, including vacation pay (excluding in connection with OMERS) regardless of whether these arose before or after Closing. The Purchaser and Indemnitor shall jointly and severally indemnify and save harmless the Vendor from and against any and all losses, damages, expenses, liabilities, claims and demands whatsoever made or brought against the Vendor by any person or Employee, association or trade union or by any federal, provincial, municipal or other government department, commission, board, bureau, agency or instrumentality or any other person or body which in any way pertains to or arises out of such liability including, without limiting the generality of the foregoing, any and all losses, damages, expenses, liabilities, claims and demands whatsoever with respect to wages, severance pay, notice of termination of employment or pay in lieu of such notice, damages for wrongful dismissal or other Employee Benefits or claims, including vacation pay (but excluding in connection with OMERS), and including any interest, award, judgment or penalty relating thereto and any costs or expenses incurred by the Vendor in defending any such claim or demand.

6.8 **Access to Purchaser's Personnel.** The Purchaser will cause Hydro One Networks Inc. to provide the Vendor with timely access to the services of the Customer Operations Manager ("**COM**") of Hydro One Networks Inc, who will be the single point of contact for all affairs. The COM will reach out to all other Hydro One Networks Inc. resources, as required. The COM will arrange for participation by appropriate personnel at Vendor's yearly municipal planning meeting and on request to Vendor's project planning meetings and presentations to Vendor's Council and will arrange for conservation and demand management education programs for local industry.

6.9 **Capital Program.** The Purchaser acknowledges and agrees that the aggregate capital expenditure budget and forecast for the Business is $20 million for the period 2015-2019 and agrees to cause the LDC or, following integration of the Business in Hydro One Networks Inc, to cause Hydro One Networks Inc. to use commercially reasonable efforts to meet such expenditure target.

6.10 **Books and Records.** The Purchaser shall preserve the books and records delivered by the Vendor to it pursuant to Section 5.3 for a period of six (6) years from the Closing Date, or for such longer period as is required by any Applicable Law, and will permit the Vendor or its authorized representatives reasonable access thereto in connection with the affairs of the Vendor relating to its matters.

6.11 **Confidentiality.** In the event that this Agreement is terminated in accordance with the provisions hereof:

(a) The Purchaser and Indemnitor hereby covenant and agree to keep confidential, in accordance with the terms of the Confidentiality Agreement, any and all information and trade secrets received by such Party from the Vendor, whether or not received prior to or after the date of this Agreement, concerning the business and affairs of the Vendor and/or the LDC (the "**Confidential Information**");

(b) subject to Subsection 6.11(c), the Purchaser and Indemnitor shall:

(i) promptly return to the Vendor all documents, computer disks, other forms of electronic storage or other materials furnished by the Vendor, or the LDC or by any of their respective representatives to the Purchaser or its representatives constituting Confidential Information, together with all copies and summaries thereof in the possession or under the control of the Purchaser, Indemnitor or its representatives and materials generated by the Purchaser or its representatives that include or refer to any part of the Confidential Information, without retaining a copy of any such material; or

(ii) alternatively, provided that the prior written consent of the Vendor has been obtained, promptly destroy all documents or other matters constituting Confidential Information in the possession or under the control of the Purchaser, Indemnitor or its representatives;

and the applicable Party shall confirm such return and/or destruction of Confidential Information to the Vendor in writing and certified by a senior officer of such Party;

(c) the Purchaser and Indemnitor shall promptly destroy the portion of the Confidential Information which consist of analyses, compilations, forecasts, studies, other material or documents prepared by the Purchaser, Indemnitor, or its representatives and shall confirm such destruction in writing and certified by a senior officer of the applicable Party;

(d) any verbal or visual Confidential Information will continue to be subject to the terms of the Confidentiality Agreement and the terms of this Section 6.11; and

(e) the Purchaser and Indemnitor shall not, directly, use for its own purposes, any Confidential Information discovered or acquired by the Party's representatives as a result of the Vendor, or the LDC making available to them any Confidential Information.

6.12 **Sentinel Lights.** Purchaser commits to provide sentinel light services for a minimum period of two (2) years following the Closing Date. Purchaser shall use commercially reasonable efforts to continue services at the similarly high level provided by HCUI prior to Closing. Should Purchaser contemplate changes to the service or contemplate discontinuing the service after two (2) years, Purchaser will consult with the Advisory Committee to ensure that their views have been considered in developing its plans.

6.13 **Best Efforts.** The Purchaser and Indemnitor shall use its best efforts (which shall not be less than commercially reasonable efforts) to cause each of the conditions set forth in Section 9.2 to be performed at or prior to Closing.

6.14 **Survival.** The covenants contained in this Article VI shall survive the Closing Date.

ARTICLE VII
REGULATORY APPROVAL

7.1 **OEB Approval.** Each of the Purchaser and the Vendor shall, at a time to be mutually agreed upon by the Parties, file or cause to be filed with the OEB applications required to be made under Subsection 86 of the OEB Act in respect of the OEB Approval as it relates to the purchase and sale of the Purchased Shares and a transfer of the Business of the LDC to Hydro One Networks Inc. and any related licence amendments or other notices required by the OEB (the "**Required Approval**"). Each of the Purchaser and the Vendor shall use their best efforts (which shall not be less than commercially reasonable efforts) to co-operate and assist the other with a view to achieving a Closing Date no later than May 31, 2015.

7.2 **Ontario Minister of Finance Notice.** The Vendor shall as promptly as practicable after the execution of this Agreement (but in no event later than the day before the Closing Date), file or cause to be filed with the Ontario Minister of Finance the notification required under Subsection 4(2) of Ontario Regulation 124/99 made under the EA. If necessary, the Vendor will also file or cause to be filed with the Ontario Minister of Finance such notification as required by Section 7 of Ontario Regulation 124/99 within thirty (30) days after the Closing Date.

7.3 **Environmental Permits.** The Parties shall co-operate to ensure promptly that any required notices of change are given with respect to all Environmental Approvals, if any.

ARTICLE VIII
TAX MATTERS

8.1 **Preparation and Filing of Tax Returns.** The Vendor shall cause HCUI to prepare and cooperate with Purchaser to submit all Tax Returns of each of the Haldimand Corporations for all periods up to and including Closing, that are not due for filing until after the Closing Date to the Purchaser for approval at least thirty (30) Business Days before the filing due-date thereof except for the debt retirement charge and sales tax returns, which shall be prepared and submitted to the Purchaser for approval at least seven (7) Business Days before the filing due-date thereof. The Vendor shall provide the Purchaser and its Representatives access to such tax supporting working papers and books and records of each of the Haldimand Corporations and Haldimand County Generation Inc. relating to the period up to and including Closing as the Purchaser reasonably requests for purposes of approving those Tax Returns. After the Purchaser has approved those Tax Returns, the Vendor shall, on a timely basis, cooperate with Purchaser to cause each of the Haldimand Corporations to file the Tax Returns.

8.2 **Books and Records Relating to Taxes.** Within thirty (30) Business Days after the Closing Date, the Vendor shall deliver to the Haldimand Corporations and the Purchaser the copies of all documents relating to Taxes of each of the Haldimand Corporations in respect of the period preceding Closing that the Vendor retained pursuant to Section 2.4(a) and all working papers, correspondence and other documents prepared after the Closing Date which relate to Taxes for such periods.

8.3 **Notification Requirements.** The Purchaser shall promptly forward to the Vendor all written notifications and other written communications from any Governmental Authority received by the Purchaser, or any of the Haldimand Corporations relating to Taxes of any of the Haldimand Corporations for all periods up to and including Closing, and shall promptly inform the Vendor of any audit proposed to be undertaken and any adjustment proposed in writing to be made by any Governmental Authority in respect of any such period. Notwithstanding the obligation of the Purchaser to give prompt notice as required above, the failure of the Purchaser to give that prompt notice shall not relieve the Vendor of its obligations under this Article VIII except to the extent (if any) that the Vendor shall have been prejudiced thereby.

8.4 **Vendor Indemnification.** From and after the Closing Date, the Vendor shall be responsible for and shall indemnify and save harmless the Purchaser for all Taxes payable by any of the Haldimand Corporations for all periods up to and including Closing, less any Tax refunds and credits received by any of the Haldimand Corporations referable to periods up to and including Closing to the extent that such amounts were not reflected in the Closing Date Financial Statements.

8.5 **Purchaser's Contest Rights.** Subject to Section 8.6, the Purchaser shall have the sole right to control, defend, settle, compromise, or prosecute in any manner an audit, examination, investigation, and other proceeding with respect to any Tax Return of any of the Haldimand Corporations or Haldimand County Generation Inc. The Purchaser shall keep the Vendor duly informed of any proceedings in connection with any matter for which the Purchaser may have a right to indemnification pursuant to this Article VIII or Article XI and promptly provide the Vendor with copies of all correspondence and documents relating to those proceedings. The Vendor shall execute or cause to be executed such documents and shall take such action as reasonably requested by the Purchaser to enable the Purchaser to take any action the Purchaser deems appropriate with respect to any proceedings in respect of which the Purchaser has contest rights under this Agreement.

8.6 **Vendor's Contest Rights.**

(a) The Vendor may at any time by written notice to the Purchaser elect to control, defend, settle, compromise or prosecute in any manner an audit, examination, investigation, or other proceeding with respect to Taxes or Tax issues related to any matter in respect of which the Purchaser may have a right of indemnification pursuant to this Article VIII or Article XI, except that:

(i) the Vendor shall deliver to the Purchaser a written agreement that the Purchaser is entitled to indemnification for all losses arising out of that audit, examination or other proceeding and that the Vendor shall be liable for the entire amount of those losses;

(ii) the Vendor may not, without the written consent of the Purchaser, settle or compromise Taxes or Tax issues related to any matter which may affect Tax liabilities of the Purchaser or of any of the Haldimand Corporations for a period following Closing; and

(iii) the Vendor shall pay to the Purchaser the amount of all Taxes (including, for greater certainty, interest and penalties) specified in the notice of assessment or other Claim from the Governmental Authority to which the Purchaser's indemnity Claim relates within 10 (ten) Business Days before the amount is required to be paid to the Governmental Authority or within 10 (ten) Business Days after the Purchaser has forwarded to the Vendor a Claim for indemnity.

(b) If the consent of the Purchaser to a settlement or compromise arranged by the Vendor is not obtained for any reason, the indemnification liability of the Vendor shall be limited to the proposed settlement amount. The Purchaser, HCUI, HCEI and/or the LDC, as applicable, shall execute or cause to be executed such documents or take such action as reasonably requested by the Vendor to enable the Vendor to take any action it deems appropriate with respect to any proceedings in respect of which the Vendor has contest rights under this Agreement. In addition:

(i) the Vendor shall keep the Purchaser duly informed of any proceedings in connection with any matter which may affect the Taxes payable by the Purchaser, HCUI, HCEI, Haldimand County Generation Inc. or the LDC; and

(ii) the Purchaser shall be promptly provided with copies of all correspondence and documents relating to those proceedings and may, at its option and its own expense, participate in those proceedings through counsel of its choice.

8.7 **Indemnification Procedures**. Except to the extent expressly provided to the contrary in this Article VIII, the general procedures regarding notice and pursuit of indemnification claims set forth in Article XI shall apply to all claims for indemnification made under this Article VIII, except that notwithstanding any provision of Article XI to the contrary, if a claim for indemnification involves any matter covered in this Article VIII, then the contest provisions of Sections 8.5 and 8.6, as applicable, shall control regarding the defence and handling of any such third-party claim that could give rise to an indemnification obligation on the part of the Vendor.

ARTICLE IX
CONDITIONS OF CLOSING

9.1 **Conditions of Closing in Favour of the Purchaser.** The sale and purchase of the Purchased Shares are subject to the following conditions for the exclusive benefit of the Purchaser, to be fulfilled or performed at or prior to Closing:

(a) **Representations and Warranties.** The representations and warranties of the Vendor contained in this Agreement which are qualified as to materiality shall be true and correct and those not qualified as to materiality shall be true and correct in all material respects at Closing, with the same force and effect as if such representations and warranties were made at and as of such time, and a certificate of:

(i) the Mayor or Deputy Mayor; and

(ii) the Clerk, or the Deputy Clerk dated the Closing Date to that effect shall have been delivered to the Purchaser.

(b) **Covenants.** All of the obligations, covenants and agreements contained in this Agreement and all related agreements to be complied with or performed by the Vendor at or prior to Closing shall have been complied with or performed, and a certificate of:

(i) the Mayor or Deputy Mayor; and

(ii) the Clerk, or the Deputy Clerk dated the Closing Date to that effect shall have been delivered to the Purchaser.

(c) **Consents and Regulatory Approvals.** There shall have been obtained, from all appropriate Persons such consents, licences, permits, approvals, certificates, registrations and authorizations as may be required to be in connection with the completion of the transactions contemplated herein, including without limitation the Required Approval.

(d) **No Action to Restrain.** No order of any court of competent jurisdiction or administrative agency shall be in existence and, no action or proceeding shall be pending or threatened in writing by any Person, to restrain or prohibit:

(i) the purchase and sale of the Purchased Shares or change in control of the LDC; or

(ii) HCUI, HCEI or the LDC from carrying on the Business as the Business is being carried on as at the date hereof.

(e) **Material Adverse Effect.** There shall not have occurred any Material Adverse Effect since the date of this Agreement.

(f) **Resignation of Directors.** All directors and officers of each of the Haldimand Corporations shall have tendered their resignations and each such individual and the Vendor shall have duly executed and delivered comprehensive releases of all their claims respectively against each of the Haldimand Corporations or the Vendor shall have provided an indemnity in form satisfactory to Purchaser, acting reasonably, for any Claims from a director or officer who does not provide such a release.

(g) **Capital Projects.** Final completion of the following projects shall have occurred:

(i) South Caledonia Voltage Conversion;

(ii) Step Down Transformer 62 Replacement;

(iii) Step Down Transformer 90 Replacement; and

(iv) Cayuga South Voltage Conversion.

If any of the conditions contained in this Section 9.1 have not been performed or fulfilled at or prior to the Closing Date to the satisfaction of the Purchaser, acting reasonably, the Purchaser may, by notice to the Vendor, terminate this Agreement and the obligations of the Parties under this Agreement and in such event the Deposit together with accrued interest shall be released to the Purchaser and the Purchaser shall be released from all obligations hereunder except those set forth in Section 6.8 and in the Confidentiality Agreement. Any such condition may be waived in whole or in part by the Purchaser without prejudice to any claims it may have for breach of covenant, representation or warranty.

9.2 **Conditions of Closing in Favour of the Vendor.** The purchase and sale of the Purchased Shares is subject to the following terms and conditions for the exclusive benefit of the Vendor, to be fulfilled or performed at or prior to Closing:

(a) **Representations and Warranties.** The representations and warranties of the Purchaser and Indemnitor contained in this Agreement which are qualified as to materiality shall be true and correct and those not qualified as to materiality shall be true and correct in all material respects at Closing, with the same force and effect as if such representations and warranties were made at and as of such time, and a certificate of a senior officer of the Purchaser and the Indemnitor executed and dated on the Closing Date to that effect shall have been delivered to the Vendor.

(b) **Covenants.** All of the obligations, covenants and agreements contained in this Agreement to be complied with or performed by the Purchaser or Indemnitor at or prior to Closing shall have been complied with or performed, and a certificate of a senior officer of the Purchaser and the Indemnitor executed and dated on the Closing Date to that effect shall have been delivered to the Vendor.

(c) **Consents and Regulatory Approvals.** There shall have been obtained, from all appropriate Persons such consents, licences, permits, approvals, certificates, registrations and authorizations as may be required to be in connection with the completion of the transactions contemplated herein, including without limitation, the Required Approval.

(d) **No Action to Restrain.** No order of any court of competent jurisdiction or administrative agency shall be in existence and, no action or proceeding shall be pending or threatened in writing by any Person, to restrain or prohibit the purchase and sale of the Purchased Shares or the change in control of the LDC.

If any of the conditions in this Section 9.2 shall not be performed or fulfilled at or prior to Closing, to the satisfaction of the Vendor, acting reasonably, the Vendor may, by notice to the Purchaser and Indemnitor, terminate this Agreement and the obligations of the Parties under this Agreement, and in such event the Vendor shall be released from all obligations hereunder except those set forth in the Confidentiality Agreement. Any such condition may be waived in whole or in part by the Vendor without prejudice to any claims it may have for breach of covenant, representation or warranty. In the event the Agreement fails to close as a result of a failure of the conditions in Section 9.2(a), Vendor may retain the Deposit and accrued interest in full satisfaction of Purchaser's obligations hereunder and Purchaser shall be released from all liability under this Agreement.

ARTICLE X
CLOSING ARRANGEMENTS

10.1 **Place of Closing.** The Closing shall take place at the head office of the Purchaser.

10.2 **Transfer.** At Closing, upon fulfilment of all the conditions set out in Article IX that have not been waived in writing by the Purchaser or the Vendor, the Vendor shall deliver to the Purchaser certificates representing all the Purchased Shares, duly endorsed in blank for transfer and will cause transfers of such shares to be duly and regularly recorded in the name of the Purchaser whereupon, subject to all other terms and conditions hereof being complied with, payment of the Purchase Price shall be paid and satisfied in the manner provided in Article II.

ARTICLE XI
REMEDIES

11.1 **Vendor's Indemnity.**

(a) Subject to Section 4.1 hereof, Vendor shall indemnify and save harmless the Purchaser, HCUI, HCEI and the LDC from and against:

(i) Claims which may be made or brought against the Purchaser, HCUI, HCEI or the LDC and all Damages which the Purchaser, HCUI, HCEI or the LDC may suffer or incur, in each case as a result of or in connection with the litigation described in Schedule 3.1(u);

(ii) Claims which may be made or brought against the Purchaser, HCUI, HCEI or the LDC and all Damages which the Purchaser, HCUI, HCEI or the LDC may suffer or incur, in each case as a result of or in connection with Remediation of the properties in accordance with Section 5.11;

(iii) Claims which may be made by or brought against HCUI, HCEI, the LDC or the Purchaser and all Damages which the Purchaser, HCUI, HCEI or the LDC may suffer or incur as a result of or in connection with which the cause of action or occurrence or conditions or obligations giving rise to the Claim or Damages arose prior to Closing and are connected with HCUI, HCEI, the LDC, the

Business, Property or former property or operations of HCUI, HCEI or the LDC or the ownership of the Purchased Shares or of the shares of HCEI or the LDC; and

(iv) Claims other than those for which indemnification is sought pursuant to subsections (i)-(iii) of this Section 11.1, which may be made or brought against the Purchaser, HCUI, HCEI or the LDC and all Damages which the Purchaser, HCUI, HCEI or the LDC may suffer or incur, in each case as a result of or in connection with any non-fulfilment of any covenant or agreement on the part of the Vendor under this Agreement or any incorrectness in or breach of any representation or warranty of the Vendor contained in this Agreement or in any certificate or other document furnished by the Vendor pursuant to this Agreement. In connection with the indemnities provided in this Section 11.1, the Vendor shall, in respect of any Claim made by any third party, be afforded an opportunity at its sole expense to resist, defend and compromise such Claim.

11.2 **Purchaser's Indemnity.**

(a) The Purchaser shall indemnify and save harmless the Vendor from and against:

(i) Claims which may be made or brought against the Vendor and all Damages which the Vendor may suffer or incur, in each case as a result of or in connection with any non-fulfilment of any covenant or agreement on the part of the Purchaser under this Agreement or any incorrectness in or breach of any representation or warranty of the Purchaser contained in this Agreement or in any certificate or other document furnished by the Purchaser pursuant to this Agreement; and

(ii) Claims which may be made or brought against the Vendor all Damages which the Vendor may suffer or incur as a result of or in connection with which the cause of action or occurrence or conditions or obligations giving rise to the cause of action arose following Closing and are connected with the LDC, the business, Property or operations or the ownership of the Purchased Shares. In connection with the forgoing, the Purchaser shall, in respect of any Claim made by any third party, be afforded an opportunity at its sole expense to resist, defend and compromise such Claim.

11.3 **Notice of Claim.** If and when the Vendor becomes entitled to make a Claim pursuant to Section 11.2 or if and when the Purchaser becomes entitled to make a Claim pursuant to Section 11.1 (in either case, the "**Indemnified Party**"), the Indemnified Party shall promptly, and in any event, within 10 (ten) days of becoming aware of the Claim, give written notice thereof to the other Party (the "**Indemnifying Party**"). Such notice shall specify whether the Claim arises as a result of a claim by a Person against the Indemnified Party (in this Article XI, a "**third party claim**") or whether the Claim does not so arise and shall also specify with reasonable particularity (to the extent that the information is available):

(a) the factual basis for the Claim; and

(b) the amount of the Claim, if known.

If, through the fault of the Indemnified Party, the Indemnifying Party does not receive notice of any Claim in time to effectively contest the determination of any liability susceptible of being contested, the Indemnifying Party shall be entitled to set off against the amount claimed by the Indemnified Party the amount of any Damages incurred by the Indemnifying Party resulting from the Indemnified Party's failure to give such notice on a timely basis.

11.4 **Co-Operation.** The Indemnified Party and the Indemnifying Party shall co-operate fully with each other with respect to third party claims, and shall keep each other fully advised with respect thereto (including supplying copies of all relevant documentation promptly as it becomes available).

11.5 **Limitation on Claims.**

(a) Notwithstanding Section 11.1 or any other provision in this Agreement:

(i) if any payment made pursuant to this Article XI is subject to HST or is deemed by Applicable Law to be inclusive of HST, the Indemnifying Party shall pay to the Indemnified Party an amount equal to the HST in connection with the payment and any additional amount hereunder; and

(ii) the Indemnifying Party shall only be liable for Damages suffered by the Indemnified Party in respect of a Claim after taking into account insurance proceeds received by the Indemnified Party in respect of the occurrence giving rise to the Claim; and Tax benefits accruing to the Indemnified Party relating to the actions taken by the Indemnified Party in respect of the Claim.

ARTICLE XII
EARLY TERMINATION

12.1 If prior to the Closing Date, there is a change in Applicable Laws such that the sale of the Purchased Shares contemplated herein is no longer exempt from tax payable pursuant to s. 94(1) of the EA, Vendor shall have the right to terminate the Agreement without penalty upon written notice to the Purchaser within thirty (30) days of the effective date of such change in Applicable Laws, in which event the Deposit together with accrued interest shall be promptly paid to the Purchaser.

ARTICLE XIII
MISCELLANEOUS

13.1 **Further Assurances.** Each Party to this Agreement covenants and agrees that, from time to time subsequent to the Closing Date, it will, at the request and expense of the requesting Party, execute and deliver all such documents, including, without limitation, all such additional conveyances, transfers, consents and other assurances and do all such other acts and things as any other Party hereto, acting reasonably, may from time to time request be executed or done in order to better evidence or perfect or effectuate any provision of this Agreement or of any agreement or other document executed pursuant to this Agreement or any of the respective obligations intended to be created hereby or thereby.

13.2 **Announcements.** The Parties shall make a joint public announcement with respect to this Agreement and the transactions herein contemplated, at such time and in such manner as may be mutually agreed upon by the Parties. Except as required by law, no other public announcement, press release, notices, statements and communications to third parties shall be made by any Party hereto without the prior consent and approval of the other Parties, provided that the Parties hereby acknowledge that the Parties may be compelled to disclose details of this Agreement and the transactions contemplated herein in connection with obtaining the OEB Approval.

13.3 **Brokerage, Commissions, etc.** It is understood and agreed that no broker, agent or other intermediary has acted for the Vendor, HCUI, HCEI, the LDC or the Purchaser, in connection with the purchase and sale of the Purchased Shares herein contemplated. The Vendor agrees to indemnify and save harmless the Purchaser from and against any claim for commission or other remuneration payable or alleged to be payable to any broker, agent or other intermediary who purports to act or to have acted for the Vendor in connection with the purchase and sale of the Purchased Shares herein contemplated. The Purchaser agrees to indemnify and save harmless the Vendor from and against any claim for commission or other remuneration payable or alleged to be payable to any broker, agent or other intermediary, who purports to act or to have acted for the Purchaser in connection with the purchase of the Purchased Shares herein contemplated.

13.4 **Notices.**

(a) Any notice or other communication required or permitted to be given hereunder shall be in writing and shall be delivered in person, transmitted by telecopy or sent by registered mail, charges prepaid, addressed as follows:

(i)	if to the Vendor:	Cayuga Administration Building 45 Munsee Street North P. O. Box 400 Cayuga, ON Canada N0A 1E0 Attention: Mayor Phone: (905) 318-5932 Fax: (905) 772-3542
(ii)	if to the Purchaser:	1908872 Ontario Inc. 483 Bay St. Toronto, ON Canada M5G 2P5 Attention: General Counsel Fax: (416) 345-6056
(iii)	if to the Indemnitor:	Hydro One Inc. 483 Bay St. Toronto, ON Canada M5G 2P5 Attention: General Counsel Fax: (416) 345-6056

(b) Any such notice or other communication shall be deemed to have been given and received on the day on which it was delivered or transmitted (or, if such day is not a Business Day, on the next following Business Day) or, if mailed, on the third Business Day following the date of mailing; provided, however, that if at the time of mailing or within three Business Days thereafter there is or occurs a labour dispute or other event that might reasonably be expected to disrupt the delivery of documents by mail, any notice or other communication hereunder shall be delivered or transmitted by telecopy as aforesaid; and

(c) A Party may at any time change its address for service from time to time by giving notice to the other Parties in accordance with this Section 13.4.

13.5 **Best Efforts.** The Parties acknowledge and agree that, for all purposes of this Agreement, an obligation on the part of the Party to use its best efforts (which shall not be less than commercially reasonable efforts) to obtain any waiver, consent, approval, permit, licence or other document shall not require such Party to make any payment to any Person for the purpose of procuring the same, other than payments for amounts due and payable to such Person, payments for incidental expenses incurred by such Person and payments required by any Applicable Law.

13.6 **Costs and Expenses.** All costs and expenses incurred in connection with this Agreement and the transactions herein contemplated shall be paid by the Party incurring such costs and expenses.

13.7 **Counterparts.** This Agreement may be executed in counterparts, each of which shall constitute an original and all of which taken together shall constitute one and the same instrument. To evidence its execution of an original counterpart of this Agreement, a Party may send a copy of its original signature on the execution page hereof to the other Parties by facsimile or other means of recorded electronic transmission (including in PDF form) and such transmission with an acknowledgement of receipt shall constitute delivery of an executed copy of this Agreement to the receiving Party.

13.8 **Guarantee.** The Indemnitor irrevocably and unconditionally guarantees to the Vendor by way of a continuing guarantee, the full and prompt payment and performance by Purchaser of Purchaser's obligations hereunder and pursuant to all associated closing documents. These obligations of the Indemnitor hereunder are separate and distinct and shall not be affected by any amendment of this Agreement or of associated closing documents by the Purchaser and Vendor. A failure or delay on the part of the Vendor in exercising a right or remedy under this guarantee does not operate as a waiver of, or impair, any rights or remedies of the Vendor however arising. Vendor need not pursue remedies against the Purchaser before being able to exercise its remedies against the Indemnitor.

13.9 **Entire Agreement.** This Agreement constitutes the entire agreement between the Parties and supersedes all prior agreements, understandings, negotiations and discussions relating to the subject matter thereof, whether oral or written. There are no representations, warranties, covenants, conditions or other agreements, express or implied, collateral, statutory or otherwise, between the Parties relating to the subject matter hereof except as specifically set forth in this Agreement,. None of the Parties has relied or is relying on any other information, discussions or understandings in entering into and completing the transactions contemplated in this Agreement. If there is any conflict or inconsistency between the provisions of this Agreement and the provisions of any document delivered on Closing, the provisions of this Agreement will govern.

13.10 **Third Party Beneficiaries.** Except as otherwise expressly provided in this Agreement, the Parties do not intend that this Agreement benefit or create any legal or equitable right, remedy or cause of action in, or on behalf of, any Person other than a Party and no Person, other than a Party, is entitled to rely on the provisions of this Agreement in any proceeding.

13.11 **Time of the Essence.** Time is of the essence in this Agreement.

13.12 **Governing Law.** This Agreement is governed by and is to be interpreted, construed and enforced in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein, without regard to conflict of law principles. Each of the Parties irrevocably attorns and submits to the exclusive jurisdiction of the courts of in any action or proceeding arising out of or relating to this Agreement.

IN WITNESS WHEREOF this Agreement has been executed by the Parties.

HYDRO ONE INC.

By:
Name:
Title:

1908872 ONTARIO INC.

By:
Name:
Title:

THE CORPORATION OF HALDIMAND COUNTY

By: ______________________________
Name: KEN HEWITT
Title: MAYOR

By: ______________________________
Name: JENNIFER SHAW
Title: ACTING CLERK

SCHEDULE 2.4
PURCHASE PRICE ADJUSTMENT

PAGE #1

HALDIMAND CORPORATIONS
CONSOLIDATED CLOSING PURCHASE PRICE ADJUSTMENTS
AS AT ____________ ____, 20__

FILE NAME: HALHYDROjn3	HCUI CONSOL. AUDITED CLOSING F/S DEC 31 '13	HCUI CONSOL. AUDITED CLOSING F/S	CHANGE INC/(DEC) TO CLOSING	PP ADJ. FACTOR	INC/(DEC) TO P.P.
	$'s	$'s	$'s	$'s	$'s
CONSOLIDATED NFA CALCULATION PER F/S:					
PROPERTY, PLANT & EQUIPMENT- (FIXED ASSETS AT NBV)	51,511,920	0	0		
DEFERRED CREDITS	-7,881,739	0	0		
	43,630,181	0	0		
+ RECLASS PORTION OF DUNNVILLE BREAKER INCLUDED IN REGULATORY ASSET/LIABILITY ACCOUNT AT CLOSE- SCHEDL	21,165	0	0		
NET INCREASE/(DECREASE) IN NFA	43,651,346		0	1.5	0
CONSOLIDATED WORKING CAPITAL (EX CASH):					
CURRENT ASSETS- SCHEDULE I	14,272,432	0			
CURRENT LIABILITIES- SCHEDULE II	10,611,597	0			
WORKING CAPITAL SURPLUS/(DEFICIENCY)	3,660,835	0	0	1.0	0
CONSOLIDATED NET DEBT CHANGE:					
NET DEBT- DECREASE/(INCREASE)- SCHEDULE III	9,858,631	0	0	1.0	0
PURCHASE PRICE ADJUSTMENT DUE TO/(FROM) VENDOR ON CLOSING					0

SCHEDULE 3.1(l)
REAL PROPERTY

Note: The Vendor and Purchaser have received electronic versions of PDF files referred to in this schedule.

Real Property – (as defined in Agreement)

1. Service Centre — 1 Greendale Drive, Caledonia
   Sen Plan 86 Pt Lot 2, Haldimand County

2. Jarvis DS — 1423 Haldimand Road 55, Jarvis
   WAL CON 8 PT Lot 6, Haldimand County

3. Decewsville DS — 2283 River Road, Cayuga
   NCAY NTR Gore Lot W River Road E Dixon Rd, Haldimand County

4. Decewsville Regulating Station
   315 Decewsville Road
   NCAY CON NTR PT Lot 42 Pt Rd Allowance RP 18R1591 Part 1 and Part 2, Haldimand County

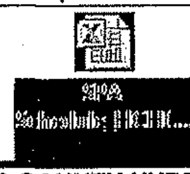
5. Canfield DS — 105 Haldimand Hwy 56, Canfield
   NCAY CON a NTR Pt Lot 13, Haldimand County Hydro

Leased Property – (as defined in Agreement)

None

Easements – (as defined in Agreement)

See enclosed chart below which includes Easements that were transferred to Vendor by the Dunnville, Haldimand and Nanticoke former Hydro-Electric Commissions and the Purchaser:

<table>
<tr><td></td><th colspan="4">HALDIMAND COUNTY HYDRO INC.</th></tr>
<tr><td rowspan="2">HALDIMAND COUNTY HYDRO INC.</td><td>As of October 13, 2000 to February 5, 2014</td><td colspan="3">Haldimand County Hydro Inc. was incorporated on October 13, 2000. Enclosed below is an Excel spreadsheet of easements registered and released as of the date of incorporation for Haldimand County Hydro Inc. to form part of the Easement Schedule for the SPA. The documents have been sorted by date, maintaining registered easements separate from easements released.</td></tr>
<tr><td>Registered Easements and Easements Released</td><td colspan="3"></td></tr>
<tr><td rowspan="4">EASEMENTS TRANSFERRED FROM HYDRO ONE (FORMERLY ONTARIO HYDRO)</td><th colspan="4">PREDECESSORS OF HALDIMAND COUNTY HYDRO INC.</th></tr>
<tr><td>Prior to October 13, 2000</td><td colspan="3">Pursuant to subsection 83.2 (29) of the <u>Power of Corporation Act</u>, R.S.O. 1990 c. P. 18, each of the former Hydro-Electric Commissions expanded its electric service area, supplied by Ontario Hydro, which resulted in the following Annexation Transfer Agreements:
• Annexation Transfer Agreement dated December 31, 1998 between Ontario Hydro and Haldimand Hydro-Electric Commission,
• Annexation Transfer Agreement dated December 18, 1998 between Ontario Hydro and Dunnville Hydro-Electric Commission, and
• Annexation Transfer Agreement dated December 31, 1998 between Ontario Hydro and Nanticoke Hydro-Electric Commission.

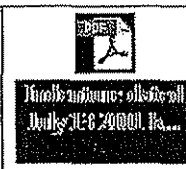
Haldimand County Hydro Inc. acquired the rights and privileges of each of the former Hydro-Electric Commissions pursuant to section 145 of the Electricity Act, 1998, by s. 3.1 (b) of By-law No. 36-2000 of the Haldimand-Norfolk Transition Board exercising the Powers of the old municipalities of Haldimand and Dunnville and the divided municipality of the City of Nanticoke pursuant to the Town of Haldimand Act, 1999 (Ontario), being Schedule B to the Few Municipal Politicians Act, 1999 (Ontario).

Accordingly, Hydro One assigned all of its interests in the rights and easements described in the enclosed documents to Haldimand County Hydro Inc.:</td></tr>
<tr><td></td><th>HALDIMAND HYDRO-ELECTRIC COMMISSION (HHEC)</th><th>DUNNVILLE HYDRO-ELECTRIC COMMISSION (DHEC)</th><th>NANTICOKE HYDRO ELECTRIC COMMISSION (NHEC)</th></tr>
<tr><td>Former Townships / Village</td><td>• North Cayuga
• Oneida
• Rainham
• Seneca
• South Cayuga</td><td>• Canborough
• Dunn
• Moulton
• Sherbrooke
• Village of</td><td>• Walpole
• Woodhouse</td></tr>
</table>

		• Village of Hagersville • Village of Caledonia • Village of Cayuga	Dunnville	
	Registered Easements (Transfer / Deed of Land and Spreadsheet, if available)	 	 	 

The Registry Office registered on January 23, 2002 the Transfer / Deed of Land for the registered easements related to the former Township of Walpole but would not register the other Transfer / Deed of Land due to legal description.

Mike McLachlin of Hedley & McLachlin provided legal advice with respect to the matter and a copy of his letter dated February 9, 2010 is enclosed below.

	Unregistered Easements (Indenture and Spreadsheet, if available)	 	 	

HALDIMAND HYDRO-ELECTRIC COMMISSION

It appears that in 1999 HHEC undertook a search of existing lines and registered Ontario Hydro easements within their jurisdiction which consisted of the former Townships of North Cayuga, Oneida, Rainham, Seneca, South Cayuga, and Walpole and Villages of Caledonia, Hagersville, and Cayuga.

Enclosed below are spreadsheets for each former Township noting the findings of their investigation. The spreadsheets refer to lines existing but no registered easement. As noted above, Hydro One transferred to Haldimand County Hydro unregistered easements and therefore these existing lines with no registered easements may be covered by an unregistered easement.

HALDIMAND HYDRO-ELECTRIC COMMISSION	North Cayuga	Oneida	Rainham	Seneca & Village of Caledonia	South Cayuga	Walpole & Village of Hagersville

HHEC: Description of ...	HHEC: Description of ...	HHEC: Description of ...	HHEC: Description of ...	HHEC: Description of ...	HHEC: Description of ...

On December 31, 1999, HHEC registered a Notice of Claim with respect to rights and privileges acquired from Ontario Hydro. A copy of each Notice of Claim is enclosed below.

Registered Notice of Claim HHE...	Registered Notice of Claim HHE...	Registered Notice of Claim HHE...	Registered Notice of Claim HHE... Registered Notice of Claim HHE...	Registered Notice of Claim HHE...	Registered Notice of Claim HHE... Registered Notice of Claim HHE...

In conjunction with registration of the Notices of Claim noted-above, a document was prepared entitled "Expired Easements" (copy enclosed below) noting that *"These Easements will not be valid unless they have been referred to in an instrument registered between July 31, 1941 and July 31, 1981".*

HHEC: Description of ...

DUNNVILLE HYDRO-ELECTRIC COMMISSION

DUNNVILLE HYDRO-ELECTRIC COMMISSION

A file folder from the former DHEC contains registered easements or easement agreements which have been copied and enclosed below:

Indenture dated September 30 L...	Notice of Claim Easement DHEC...	Transfer Deed of Land Registr...	Transfer Deed of Land Registr...

Note:

- No registered easements have been obtained for sentinel lights located on private property.
- Vendor makes no representation that any of the Real Property and Easements is free from First Nations land claims—Purchaser takes title subject to any existing or future First Nations land claims.

SCHEDULE 3.1(m)
INTELLECTUAL PROPERTY

1. LDC- the Logo not registered at Trademark Office.

2. Domain name – "hchydro.ca" – registered with Webnames until April 27, 2018
3. Website – "haldimandcountyhydro.ca" – registered through Via Net. Expires March 11, 2015.

SCHEDULE 3.1(p)
HCUI EMPLOYMENT AND EMPLOYEE BENEFIT MATTERS

1. Collective Agreement between Haldimand County Hydro Inc. and Local Union 636 of the International Brotherhood of Electrical Workers ("IBEW") – effective April 1, 2013 to March 31, 2017

2. Haldimand County Hydro Policy No. [redacted] Policy Manual for Non-Union Staff – revised September 30, 2013

3. Benefits Administration Agreement between MEARIE Management Inc. ("MMI") and Haldimand County Hydro Inc. – for the period January 1, 2011 to December 31, 2011 with automatic annual renewals

4. Accidental Death and Dismemberment ("AD&D") offered under AIG Insurance Company of Canada Policy No. [redacted]

5. Extended Health Care, including Vision Care and Global Medical Assistance, offered under Great-West Life Policy No. [redacted]

6. Dental Care offered under Great-West Life Policy No [redacted]

7. Long Term Disability ("LTD") offered under Desjardins Insurance Policy No. [redacted]

8. Life Insurance, including Basic Term, Employee Supplementary, Employee Optional, and Spousal Optional offered under Desjardins Insurance Policy No. [redacted]

9. OMERS Pension Plan participation by Haldimand County Utilities Inc. – Group No. [redacted]

10. Employee Assistance Plan ("EAP") Agreement between Haldimand County Hydro Inc. and Haldimand-Norfolk Resource, Education and Counselling Help ("R.E.A.C.H.") – effective July 1, 2014 to June 30, 2015

11. Sick Leave Plan offered by Haldimand County Hydro Inc. (self-insured)

12. Safety Prescription Eye Glasses offered by Haldimand County Hydro Inc. (self-insured)

13. Orthodontic services offered by Haldimand County Hydro Inc. (self-insured)

14. Tuition Reimbursement offered by Haldimand County Hydro Inc. under Policy No. 1.4 Staff Development – issued April 24, 2002 (self-insured)

15. Personal Use of Corporate Vehicles by On-Call Line Personnel, Line Supervisor and Meter Supervisor, offered by Haldimand County Hydro Inc.

16. Use of Corporate Mobile Devices by various employees offered by Haldimand County Hydro Inc.

17. Employment Contract between Haldimand County Hydro Inc. an[redacted]r the temporary position of Customer Service & Collections Clerk – effective January 31, 2014 until September 26, 2014

18. Employment Contract between Haldimand County Hydro Inc. an[redacted]r the temporary position of Engineering – Co-op Student – effective January 6, 2014 until August 29, 2014

Exception referred to in Section 3.1(p) (c)

1. Retirement Life Insurance offered under Desjardins Insurance Policy No[redacted] for Retirees pre 2002 (i.e. closed class)

Exception referred to in Section 3.1(p) (d)

1. Workplace Safety & Insurance Board ("WSIB") Claim No[redacted] -[redacted] – on account of occupational noise induced hearing loss, while employed as a lineperson by the former Haldimand Hydro-Electric Commission and its predecessor companies from June 15, 1960 to retirement on March 18, 1991. The first acknowledgement by the WSIB of this claim was in April 2005.

SCHEDULE 3.1(s)
INSURANCE POLICIES

1. MEARIE

Name of Insured:
Haldimand County Utilities Inc.
Coverage:

1. General Liability including:
    - Premises and Operations
    - Products and Completed Operations
2. Bodily Injury Liability
3. Personal Injury Liability
4. Property Damage Liability
5. Tenant's Legal Liability
6. Environmental Impairment
7. Errors & Omissions/Professional Liability
8. Non-Owned Automobile
9. Legal Expense Reimbursement (re: Conflict of Interest and Occupational Health &
Safety)
10. Enhanced Plus+ Directors & Officers Liability
11. Privacy Liability & Network Security Breach

Limit: $24,000,000 per occurrence
Insurer: Municipal Electric Association Reciprocal Insurance Exchange
Policy Number: [redacted]
Policy Period: January 1, 2014 – January 1, 2015 (12:01am)
Additional Named Insured:
Haldimand County Hydro Inc.
Haldimand County Energy Inc.

Significant Outstanding Claims

1. *Stray Voltage Claim* – [redacted] Selkirk View Farms Ltd commenced legal action against Ontario Hydro, Ontario Power Generation, Nanticoke Electric Commission and The Corporation of Haldimand County.
    a. Today this claim rest with Haldimand County Hydro. The trial date has been set for September 22, 2014.
    b. This claim is being defended through our liability coverage with MEARIE.

2. Frank Cowan Company

Name of Insured:
Haldimand County Utilities Inc.,
Coverage

1. Casualty (includes Comprehensive Crime and Board Members Accident)
2. Property
3. Equipment Breakdown
4. Automobile
5. Excess Automobile

Limit: See Policy for Insured Values.
Insurer: The Guarantee Company of North America, Northbridge General Insurance Corporation Temple Insurance Company.

Policy Number[redacted]
Policy Period: December 31, 2014 – December 31, 2015 (12:01am)
Additional Named Insured:
Haldimand County Hydro Inc.
Haldimand County Energy Inc.
Haldimand County Generation Inc.

Significant Outstanding Claims
No outstanding claims at time of reporting.

Note:

- See Schedule 3.1 (n) for MEARIE and Frank Cowan Insurance
- See Schedule 3.1 (p) for listing of employee benefit contacts and S.1(n) for material contracts

SCHEDULE 3.1(u)
VENDOR LITIGATION

1. Haldimand County Hydro is defending a CVOR Charge regarding overweight vehicle.
    a. Incident took place June 2013. We have engaged Burness Paralegal to represent our interests. Charges if upheld will result in demerit points against the company and employee.
    b. Pre-trial court date May 13, 2014 in Brantford.
    c. Recommendation to settle and accepted by Haldimand County Hydro Inc.
    d. Legal costs anticipated to be under $5,000.
2. Stray Voltage Claim -[redacted] Selkirk View Farms Ltd commenced legal action against Ontario Hydro, Ontario Power Generation, Nanticoke Electric Commission and The Corporation of Haldimand County.
    a. Today this claim rest with Haldimand County Hydro. The trial date has been set for September 22, 2014.
    b. This claim is being defended through our liability coverage with MEARIE.
    c. This item is crossed referenced from Schedule 3.1(s)

SCHEDULE 3.1 (bb)
LICENCES

1. OEB Distribution Licence – Haldimand County Hydro Inc. - ED-2002-0539
    a. Valid until October 20, 2023.
2. Provisional Licenced Electrical Contractor – Haldimand County Energy Inc. - #7003014 – Date of registration November 28, 2006 – date of expiry – December 31, 2014.
3. Commercial Vehicle Operator's Registration (CVOR) – [redacted]
4. Industry Canada – Radio Licenses
    a. 3782994 – Call Sign VAX285 – Clanbrassil
    b. 3782995 – mobile units – Caledonia
    c. 4575792 - Call Sign VAX549 – 1 Greendale Drive, Caledonia
5. Software Licences –
    a. Autocad 11
    b. CYME CYME/DIST/SRV 1
    c. CYME/MAP/SRV 1
    d. CYME/SUB/SRV 1
    e. CYMTCC/SVR 1
    f. Oracle VM Support 4
    g. ESRI ArcFM Designer 3
    h. Harris EIS Dashboard Support 1
    i. mCare/Meter Exchange Support 1
    j. MDMR Support 1
    k. NorthStar/eDocs/DSM Support 1
    l. Customer Connect Platform Support 1
    m. Customer Connect Home Support 1
    n. Customer Connect Bill Support 1
    o. Customer Connect CIS Support 1
    p. NorthStar GUI Support 30
    q. NorthStar Reports Anywhere Support 1
    r. Great Plains User Licenses (Concurrent) 8

SCHEDULE 6.3
COMMUNITY SUPPORT

The Purchaser shall offer the following Community Citizenship Plan in Haldimand County:

- PowerPlay (up to $25,000 per facility);
- Employee Volunteer Grant ($1,000 per employee with 50 or more hours of volunteer time);
- Continuation of support for local events in Haldimand County.

SCHEDULE 6.6
CURRENT RATES

Haldimand Country Hydro Inc.

Tariff of Rates and Charges

Rate Class	Dx Charges	May 1, 2014
Residential	Serv. Chg [$/month]	$17.01
	Var. Chg [$/kWh]	0.0248
GS < 50 kW	Serv. Chg [$/month]	$26.94
	Var. Chg [$/kWh]	0.0190
GS 50-4999 kW	Serv. Chg [$/month]	83.61
	Var. Chg [$/kW]	3.9339
Unmetered	Serv. Chg [$/month]	$19.51
Scattered Load	Var. Chg [$/kWh]	0.0025
Sentinel Lights	Serv. Chg [$/month]	$14.23
	Var. Chg [$/kW]	36.7261
Street Lighting	Serv. Chg [$/month]	$5.70
	Var. Chg [$/kW]	14.5882
Embedded	Serv. Chg [$/month]	$464.17
Distributor	Var. Chg [$/kW]	1.4304

2014 Rates per EB-2013-0134

Base Rates only

HYDRO ONE INC. 2013 FINANCIAL STATEMENTS

HYDRO ONE INC.
MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 13, 2014.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, management has assessed the design and operating effectiveness of the Company's internal control over financial reporting in accordance with the criteria set forth in Internal Control – Integrated Framework (1992), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2013. The effectiveness of these internal controls and findings is reported to the Audit and Finance Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Shareholder. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit findings.

The President and Chief Executive Officer and the Chief Administration Officer and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting.

On behalf of Hydro One Inc.'s management:

Carmine Marcello	Sandy Struthers
President and Chief Executive Officer	Chief Administration Officer and Chief Financial Officer

HYDRO ONE INC.
INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying Consolidated Financial Statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012, the consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of Consolidated Financial Statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Consolidated Financial Statements. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the Consolidated Financial Statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the Consolidated Financial Statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2013 and December 31, 2012, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
February 13, 2014

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars, except per share amounts)	**2013**	**2012**
Revenues		
Distribution (includes $160 related party revenues; 2012 – $155) *(Note 20)*	4,484	4,184
Transmission (includes $1,517 related party revenues; 2012 – $1,482) *(Note 20)*	1,529	1,482
Other	61	62
	6,074	5,728
Costs		
Purchased power (includes $2,500 related party costs; 2012 – $2,409) *(Note 20)*	3,020	2,774
Operation, maintenance and administration *(Note 20)*	1,106	1,071
Depreciation and amortization *(Note 5)*	676	659
	4,802	4,504
Income before financing charges and provision for payments in lieu of corporate income taxes	1,272	1,224
Financing charges *(Note 6)*	360	358
Income before provision for payments in lieu of corporate income taxes	912	866
Provision for payments in lieu of corporate income taxes *(Notes 7, 20)*	109	121
Net income	803	745
Other comprehensive income	–	1
Comprehensive income	803	746
Basic and fully diluted earnings per common share *(dollars) (Note 18)*	7,850	7,280
Dividends per common share declared *(dollars) (Note 19)*	2,000	3,523

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS
At December 31, 2013 and 2012

December 31 (millions of Canadian dollars)	**2013**	**2012**
Assets		
Current assets:		
Cash and cash equivalents *(Note 13)*	565	195
Accounts receivable (net of allowance for doubtful accounts – $36; 2012 – $23) *(Note 8)*	923	845
Due from related parties *(Note 20)*	197	154
Regulatory assets *(Note 11)*	47	29
Materials and supplies	23	23
Deferred income tax assets *(Note 7)*	18	18
Derivative instruments *(Note 13)*	6	–
Investment *(Notes 13, 20)*	251	–
Other	28	22
	2,058	1,286
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	23,820	22,650
Less: accumulated depreciation	8,615	8,145
	15,205	14,505
Construction in progress	1,078	1,055
Future use land, components and spares	148	147
	16,431	15,707
Other long-term assets:		
Regulatory assets *(Note 11)*	2,636	3,098
Investment *(Notes 13, 20)*	–	251
Intangible assets (net of accumulated amortization – $252; 2012 – $305) *(Note 10)*	313	267
Goodwill	133	133
Deferred debt costs	36	34
Derivative instruments *(Note 13)*	6	19
Deferred income tax assets *(Note 7)*	11	14
Other	1	2
	3,136	3,818
Total assets	21,625	20,811

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)
At December 31, 2013 and 2012

December 31 (millions of Canadian dollars, except number of shares)	**2013**	**2012**
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	31	42
Accounts payable	62	140
Accrued liabilities *(Notes 7, 15, 16)*	733	578
Due to related parties *(Note 20)*	230	261
Accrued interest	100	95
Regulatory liabilities *(Note 11)*	85	40
Long-term debt payable within one year (includes $506 measured at fair value; 2012 – $0) *(Notes 12, 13)*	756	600
	1,997	1,756
Long-term debt (includes $256 measured at fair value; 2012 – $769) *(Notes 12, 13)*	8,301	7,879
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	1,488	1,416
Deferred income tax liabilities *(Note 7)*	1,129	944
Pension benefit liability *(Note 15)*	845	1,515
Environmental liabilities *(Note 16)*	239	227
Regulatory liabilities *(Note 11)*	163	181
Net unamortized debt premiums	20	23
Asset retirement obligations *(Note 17)*	14	15
Long-term accounts payable and other liabilities	14	25
	3,912	4,346
Total liabilities	14,210	13,981
Contingencies and commitments (Notes 22, 23)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 18, 19)*	323	323
Shareholder's equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 18, 19)*	3,314	3,314
Retained earnings	3,787	3,202
Accumulated other comprehensive loss	(9)	(9)
Total shareholder's equity	7,092	6,507
Total liabilities, preferred shares and shareholder's equity	21,625	20,811

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

James Arnett
Chair

Michael J. Mueller
Chair, Audit and Finance Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
For the years ended December 31, 2013 and 2012

Year ended December 31, 2013 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholder's Equity
January 1, 2013	3,314	3,202	(9)	6,507
Net income	–	803	–	803
Other comprehensive income	–	–	–	–
Dividends on preferred shares	–	(18)	–	(18)
Dividends on common shares	–	(200)	–	(200)
December 31, 2013	3,314	3,787	(9)	7,092

Year ended December 31, 2012 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholder's Equity
January 1, 2012	3,314	2,827	(10)	6,131
Net income	–	745	–	745
Other comprehensive income	–	–	1	1
Dividends on preferred shares	–	(18)	–	(18)
Dividends on common shares	–	(352)	–	(352)
December 31, 2012	3,314	3,202	(9)	6,507

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Operating activities		
Net income	803	745
Environmental expenditures	(16)	(18)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	597	589
Regulatory assets and liabilities	3	12
Deferred income taxes	(2)	(9)
Other	8	6
Changes in non-cash balances related to operations *(Note 21)*	11	(31)
Net cash from operating activities	1,404	1,294
Financing activities		
Long-term debt issued	1,185	1,085
Long-term debt retired	(600)	(600)
Dividends paid	(218)	(370)
Change in bank indebtedness	(11)	3
Other	(5)	(1)
Net cash from financing activities	351	117
Investing activities		
Capital expenditures *(Note 21)*		
Property, plant and equipment	(1,333)	(1,373)
Intangible assets	(79)	(90)
Other	27	19
Net cash used in investing activities	(1,385)	(1,444)
Net change in cash and cash equivalents	370	(33)
Cash and cash equivalents, beginning of year	195	228
Cash and cash equivalents, end of year	565	195

See accompanying notes to 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. The electricity rates of these businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These 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 Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. Certain comparative figures have been reclassified to conform to the presentation of these Consolidated Financial Statements (see Note 21 – Consolidated Statements of Cash Flows). In the opinion of management, these Consolidated Financial Statements include all adjustments that are necessary to fairly state the financial position and results of operations of Hydro One as at, and for the year ended December 31, 2013.

Hydro One performed an evaluation of subsequent events through to February 13, 2014, the date these Consolidated Financial Statements were issued, to determine whether any events or transactions warranted recognition and disclosure in these Consolidated Financial Statements. See Note 25 – 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, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, 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 Company's Transmission Business includes the separately regulated transmission business of Hydro One Networks. The Company's consolidated Distribution Business includes Hydro One Brampton Networks, Hydro One Remote Communities, as well as the separately regulated distribution business of Hydro One Networks.

The OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' transmission and distribution businesses, as well as by Hydro One Remote Communities, beginning with the year 2012. Hydro One Brampton Networks currently uses Canadian GAAP for its distribution rate-setting purposes.

Transmission

In May 2010, Hydro One Networks filed a cost-of-service application with the OEB for 2012 transmission rates. The OEB approved a revenue requirement of $1,418 million for 2012, along with new 2012 uniform transmission rates, with an effective date of January 1, 2012. In May 2012, Hydro One Networks filed a cost-of-service application with the OEB for 2013 transmission rates, seeking approval for a 2013 revenue requirement of $1,465 million. In December 2012, the OEB approved a revenue requirement of $1,438 million for 2013. The reduced approved revenue requirement included reductions to proposed operation, maintenance and administration costs, and capital expenditures.

Distribution

In 2010, the OEB approved a revised 2011 revenue requirement of $1,218 million and 2011 distribution rates. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year. In June 2012, Hydro One Networks filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2013 distribution rates. In December 2012, the OEB approved an increase in average distribution rates of approximately 1.3%, with an effective date of January 1, 2013.

In September 2011, Hydro One Brampton Networks filed an IRM application with the OEB for 2012 distribution rates. In January 2012, the OEB approved a reduction in distribution rates of approximately 13.2%, with an effective date of January 1, 2012. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates. In August 2012, Hydro One Brampton Networks filed an IRM application with the OEB for 2013 distribution rates. In December 2012, the OEB approved an increase in average distribution rates of approximately 0.3%, with an effective date of January 1, 2013.

In November 2011, Hydro One Remote Communities filed an IRM application with the OEB for 2012 rates. In March 2012, the OEB approved an increase of approximately 1.1% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2012. In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 rates, seeking approval for a 2013 revenue requirement of $53 million. In June 2013, the OEB approved a revenue requirement of $51 million for 2013.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been 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 future 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.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

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 electricity 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 electricity 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.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are estimated and recorded based on wholesale electricity purchases. 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 billed 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 110 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.

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% 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 judgement 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 their 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 tax asset to report the net 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 realized.

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

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

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

Property, Plant and Equipment

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

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

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 land access rights.

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), consulting, engineering, overheads and attributable capitalized 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.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing 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.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete 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, except for 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 OEB approval of 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, 2013. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate (%)	
	Service Life	Range	Average
Transmission	57 years	1% – 2%	2%
Distribution	42 years	1% – 20%	2%
Communication	19 years	1% – 15%	5%
Administration and service	15 years	3% – 20%	6%

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 10%.

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 such gain or loss 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 that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a 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.

For the year ended December 31, 2013, based on the qualitative assessment performed as at September 30, 2013, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2013.

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 most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is 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 December 31, 2013, 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 such amounts 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 within financing charges in the Consolidated Statements of Operations and Comprehensive Income. 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 amortization of net unamortized hedging losses on the Company's discontinued cash flow hedges, and the change in fair value on the existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective-interest method over the term of the allocated hedged debt. Hydro One presents net income and OCI 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; 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 and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates 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 13 – Fair Value of Financial Instruments and Risk Management.

The Company's 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.

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 hedging relationships.

The accounting guidance for derivative instruments 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 on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments 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, net of tax, is reported as a component of accumulated OCI (AOCI) and is 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 derivative instruments 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 and had no embedded derivatives at December 31, 2013 or 2012.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly 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 plans 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 plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on 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 on the Consolidated Balance Sheets. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

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 recorded on an accrual basis for financial reporting purposes. 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. 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 fair valued at the end of each year.

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

All future pension 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.

Post-retirement and post-employment benefits

Post-retirement and post-employment benefits are recorded and included in rates 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.

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

For post-retirement benefits, 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. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment 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), a multiemployer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on members' length of service and salary. Both participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated by member entity. OMERS is registered with the Financial Services Commission of Ontario under Registration #0345983. At December 31, 2012, OMERS had approximately 429,000 members, with approximately 283 members being current employees of Hydro One Brampton Networks.

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 obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton Networks' employees. Hydro One recognizes its contributions to the OMERS plan 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.

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 judgements 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. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. 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 judgements 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 where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. 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 contaminated land assessment and remediation (LAR) 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. Where an asset is no longer in service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

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

Recently Adopted Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset on the Consolidated Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement. The ASU was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity's financial position. This ASU was required to be applied retrospectively and was effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. The adoption of this ASU did not have an impact on the Company's Consolidated Financial Statements.

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This ASU requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount reclassified is required under US GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under US GAAP that provide additional detail about those amounts. This ASU was required to be applied prospectively and was effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. The adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU provides guidance on the presentation of unrecognized tax benefits. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, and should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The adoption of this ASU is not anticipated to have a significant impact on the Company's Consolidated Financial Statements.

4. BUSINESS ACQUISITION

Norfolk Power Purchase Agreement

On April 2, 2013, Hydro One reached an agreement with The Corporation of Norfolk County to acquire 100% of the common shares of Norfolk Power Inc. (Norfolk Power), an electricity distribution and telecom company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Norfolk Power will be approximately \$93 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2014. In anticipation of the Norfolk Power acquisition, the Company made a refundable deposit totaling \$5 million, which was recorded in other current assets on the interim Consolidated Balance Sheet.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Depreciation of property, plant and equipment	533	522
Amortization of intangible assets	48	48
Asset removal costs	79	70
Amortization of regulatory assets	16	19
	676	659

6. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Interest on long-term debt	416	421
Other	9	12
Less: Interest capitalized on construction and development in progress	(51)	(59)
Gain on interest-rate swap agreements	(11)	(12)
Interest earned on investments	(3)	(4)
	360	358

7. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Income before provision for PILs	912	866
Canadian federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	242	230
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(72)	(42)
Pension contributions in excess of pension expense	(23)	(23)
Interest capitalized for accounting but deducted for tax purposes	(13)	(15)
Overheads capitalized for accounting but deducted for tax purposes	(14)	(14)
Prior year's adjustments	(8)	(2)
Non-refundable investment tax credits	(4)	(8)
Environmental expenditures	(4)	(5)
Post-retirement and post-employment benefit expense in excess of cash payments	4	–
Other	(1)	(1)
Net temporary differences	(135)	(110)
Net permanent differences	2	1
Total provision for PILs	109	121

The major components of income tax expense are as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Current provision for PILs	111	130
Deferred recovery of PILs	(2)	(9)
Total provision for PILs	109	121
Effective income tax rate	11.98%	13.96%

The current provision for PILs is remitted to, or received from, the Ontario Electricity Financial Corporation (OEFC). At December 31, 2013, $29 million due from the OEFC was included in due from related parties on the Consolidated Balance Sheet (December 31, 2012 – $10 million included in due to related parties).

The total provision for PILs includes deferred recovery of PILs of $2 million (2012 – $9 million) that is not included in the rate-setting process, using the 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.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company’s assets and liabilities. At December 31, 2013 and 2012, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	7	7
Environmental expenditures	5	4
Depreciation and amortization in excess of capital cost allowance	–	3
Other	(1)	–
Total deferred income tax assets	11	14
Less: current portion	–	–
	11	14

December 31 (millions of Canadian dollars)	**2013**	**2012**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,556)	(1,344)
Post-retirement and post-employment benefits expense in excess of cash payments	542	519
Environmental expenditures	66	62
Regulatory amounts that are not recognized for tax purposes	(144)	(147)
Goodwill	(20)	(19)
Other	1	3
Total deferred income tax liabilities	(1,111)	(926)
Less: current portion	18	18
	(1,129)	(944)

During 2013, there was no change in the rate applicable to future taxes (2012 – a change in rate applicable to future rates generated a $60 million increase).

8. ACCOUNTS RECEIVABLE

December 31 (millions of Canadian dollars)	**2013**	**2012**
Accounts receivable – billed	268	224
Accounts receivable – unbilled	691	644
Accounts receivable, gross	959	868
Allowance for doubtful accounts	(36)	(23)
Accounts receivable, net	923	845

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2013 and 2012:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Allowance for doubtful accounts – January 1	(23)	(18)
Write-offs	24	17
Additions to allowance for doubtful accounts	(37)	(22)
Allowance for doubtful accounts – December 31	(36)	(23)

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2013 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	12,413	4,215	671	8,869
Distribution	8,498	3,046	316	5,768
Communication	1,060	560	53	553
Administration and Service	1,380	716	38	702
Easements	617	78	–	539
	23,968	8,615	1,078	16,431

December 31, 2012 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	11,840	3,990	641	8,491
Distribution	8,005	2,879	234	5,360
Communication	1,024	516	57	565
Administration and Service	1,314	668	123	769
Easements	614	92	–	522
	22,797	8,145	1,055	15,707

Financing charges capitalized on property, plant and equipment under construction were $48 million in 2013 (2012 – $56 million).

10. INTANGIBLE ASSETS

December 31, 2013 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	557	249	3	311
Other	5	3	–	2
	562	252	3	313

December 31, 2012 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	451	301	116	266
Other	5	4	–	1
	456	305	116	267

Financing charges capitalized on intangible assets under development were $3 million in 2013 (2012 – $3 million). The estimated annual amortization expense for intangible assets is as follows: 2014 – $52 million; 2015 – $52 million; 2016 – $52 million; 2017 – $52 million; and 2018 – $44 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Regulatory assets:		
Deferred income tax regulatory asset	1,145	954
Pension benefit regulatory asset	845	1,515
Post-retirement and post-employment benefits	308	320
Environmental	266	249
Pension cost variance	80	61
OEB cost assessment differential	9	6
DSC exemption	7	2
Long-term project development costs	5	5
Rider 2	–	10
Other	18	5
Total regulatory assets	2,683	3,127
Less: current portion	47	29
	2,636	3,098
Regulatory liabilities:		
External revenue variance	81	61
Rider 8	55	45
Retail settlement variance accounts	35	54
Deferred income tax regulatory liability	19	16
Rider 9	19	–
PST savings deferral	17	13
Hydro One Brampton Networks rider	8	–
Rider 3	–	9
Rural and remote rate protection variance	–	6
Other	14	17
Total regulatory liabilities	248	221
Less: current portion	85	40
	163	181

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2013 provision for PILs would have been higher by approximately $139 million (2012 – $136 million).

Pension Benefit Regulatory Asset

The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2013 OCI would have been higher by $670 million (2012 – lower by $736 million).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2013 OCI would have been higher by $12 million (2012 – lower by $197 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2013, the environmental regulatory asset decreased by $3 million (2012 – $3 million) to reflect related changes in the Company's PCB liability, and increased by $26 million (2012 – $2 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2013 operation, maintenance and administration expenses would have been higher by $23 million (2012 – lower by $1 million). In addition, 2013 amortization expense would have been lower by $16 million (2012 – $18 million), and 2013 financing charges would have been higher by $10 million (2012 – $11 million).

Pension Cost Variance

A pension cost variance account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In the absence of rate-regulated accounting, 2013 revenue would have been lower by $19 million (2012 – $18 million).

OEB Cost Assessment Differential

In April 2010, the OEB announced its decision regarding the Company's rate application in respect of Hydro One Networks' distribution business for 2010 and 2011. As part of this decision, the OEB also approved the distribution-related OEB Cost Assessment Differential Account to record the difference between the amounts approved in rates and actual expenditures with respect to the OEB's cost assessments.

DSC Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the Distribution System Code (DSC), with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One

Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that expenditures for identified specific expenditures can be recorded in a deferral account, subject to the OEB's review at a future date.

Long-Term Project Development Costs

In May 2009, the OEB approved the creation of a deferral account to record Hydro One Networks' costs of preliminary work to advance certain transmission projects identified in the Company's 2009 and 2010 transmission rate applications. In March 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 2009 request from the Ministry of Energy and Infrastructure. In December 2012, the OEB approved the recovery of the December 31, 2012 balance, including accrued interest, to be recovered over a one-year period from January 1, 2014 to December 31, 2014.

Rider 2

In April 2006, the OEB approved Hydro One Networks' distribution-related deferral account balances. The Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved the balance of the Rider 2 regulatory account for disposition as part of Rider 9, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

Rider 8

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

Retail Settlement Variance Accounts (RSVAs)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In December 2012, the OEB approved the disposition of the total RSVA balance accumulated from January 2010 to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014. Hydro One has continued to accumulate a net liability in its RSVAs since December 31, 2011.

Rider 9

In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved for disposition certain distribution-related deferral account balances, including RSVA amounts and balances of Rider 2 and Rider 3, accumulated up to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost-of-service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administration expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable, and calculations for tracking and refund were requested by the OEB. For Hydro One Networks' transmission revenue requirement, PST was included between July 1, 2010 and December 31, 2010 and recorded in a deferral account, per direction from the OEB. For Hydro One Networks' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2013 and recorded in a deferral account, per direction from the OEB.

Hydro One Brampton Networks Rider

In December 2013, the OEB issued a decision for Hydro One Brampton Networks' 2014 distribution rates. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVAs. The OEB ordered that the approved balances be aggregated into a single regulatory account and disposed of through a rate rider over a two-year period from January 1, 2014 to December 31, 2015.

Rider 3

In December 2008, the OEB approved certain distribution-related deferral account balances, including RSVA amounts, deferred tax changes, OEB costs and smart meters. The OEB approved the disposition of the Rider 3 balance accumulated up to April 2008, including accrued interest, to be disposed over a 27-month period from February 1, 2009 to April 30, 2011. In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved the balance of Rider 2 for disposition as part of Rider 9.

Rural and Remote Rate Protection Variance (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. The OEB has approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked by the Company in the RRRP variance account. At December 31, 2013, the RRRP variance account had a $2 million debit balance, which is included in Other regulatory assets.

12. DEBT AND CREDIT AGREEMENTS

Short-Term Notes

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1,000 million. These 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 December 31, 2013 and 2012.

Hydro One has a $1,500 million committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2018. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility is unsecured and supports the Company's Commercial Paper Program. The Company may use the credit facility for general corporate purposes, including meeting short-term funding requirements. The obligation of each lender to make any credit extension to the Company under its credit facility is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3,000 million. At December 31, 2013, $1,815 million remained available for issuance until October 2015.

The following table presents the outstanding long-term debt at December 31, 2013 and 2012:

December 31 (millions of Canadian dollars)	**2013**	**2012**
5.00% Series 15 notes due 2013	–	600
3.13% Series 19 notes due 2014[1]	750	750
2.95% Series 21 notes due 2015[1]	500	500
Floating-rate Series 22 notes due 2015[2]	50	50
4.64% Series 10 notes due 2016	450	450
Floating-rate Series 27 notes due 2016[2]	50	50
5.18% Series 13 notes due 2017	600	600
2.78% Series 28 notes due 2018	750	–
4.40% Series 20 notes due 2020	300	300
3.20% Series 25 notes due 2022	600	600
7.35% Debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
4.59% Series 29 notes due 2043	435	–
5.00% Series 11 notes due 2046	325	325
4.00% Series 24 notes due 2051	225	225
3.79% Series 26 notes due 2062	310	310
	9,045	8,460
Add: Unrealized marked-to-market loss[1]	12	19
Less: Long-term debt payable within one year	(756)	(600)
Long-term debt	8,301	7,879

[1] The unrealized marked-to-market loss relates to $500 million of the Series 19 notes due 2014, and $250 million of the Series 21 notes due 2015. The unrealized marked-to-market loss is offset by a $12 million (2012 – $19 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 13 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[2] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

In 2013, Hydro One issued $1,185 million (2012 – $1,085 million) of long-term debt under the MTN Program, and repaid the $600 million MTN Series 15 notes (2012 – redeemed $600 million MTN Series 3 notes).

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 13 – Fair Value of Financial Instruments and Risk Management.

13. 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 occur 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

At December 31, 2013 and 2012, the Company's carrying amounts of accounts receivable, due from related parties, cash and cash equivalents, bank indebtedness, accounts payable, and due to related parties 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 at December 31, 2013 and 2012 are as follows:

December 31 (millions of Canadian dollars)	2013 Carrying Value	2013 Fair Value	2012 Carrying Value	2012 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	506	506	512	512
$250 million of MTN Series 21 notes[2]	256	256	257	257
Other notes and debentures[3]	8,295	9,018	7,710	9,188
	9,057	9,780	8,479	9,957

[1] The fair value of $500 million of the MTN Series 19 notes 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 notes 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 notes and the MTN Series 21 notes 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 Derivative Instruments

At December 31, 2013, the Company had interest-rate swaps totaling $750 million (2012 – $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 was equal to about 8% (2012 – 9%) of its total long-term debt of $9,057 million (2012 – $8,479 million). At December 31, 2013, the Company had 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 notes 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 notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2013, the Company also had interest-rate swaps with a total notional value of $900 million (2012 – $900 million) classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(c) three $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 11, 2013 to December 11, 2014, from February 19, 2013 to February 19, 2014, and from February 19, 2014 to November 19, 2014;

(d) two $50 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 24, 2013 to January 24, 2014, and from January 24, 2014 to January 24, 2015; and

(e) 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 MTN Series 27 notes from December 3, 2013 to December 3, 2014.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2013 and 2012 is as follows:

December 31, 2013 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	565	565	565	–	–
Investment	251	251	–	251	–
Derivative instruments					
Fair value hedges – interest-rate swaps	12	12	–	12	–
	828	828	565	263	–
Liabilities:					
Bank indebtedness	31	31	31	–	–
Long-term debt	9,057	9,780	–	9,780	–
	9,088	9,811	31	9,780	–

December 31, 2012 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	195	195	195	–	–
Investment	251	251	–	251	–
Derivative instruments					
Fair value hedges – interest-rate swaps	19	19	–	19	–
	465	465	195	270	–
Liabilities:					
Bank indebtedness	42	42	42	–	–
Long-term debt	8,479	9,957	–	9,957	–
	8,521	9,999	42	9,957	–

Cash and cash equivalents include cash and short-term investments. At December 31, 2013, short-term investments consisted of bankers' acceptances and money market funds totaling $515 million (2012 – $195 million). The carrying values are representative of fair value because of the short-term nature of these instruments.

The investment represents the Province of Ontario Floating-Rate Notes maturing in November 2014. The fair value of the investment is determined using inputs other than quoted prices that are observable for the asset, with unrecognized gains or losses recognized in financing charges. The Company obtains quotes from an independent third party for the fair value of the investment, who uses the market price of similar securities adjusted for changes in observable inputs such as maturity dates and interest rates.

The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the fair value levels during the years ended December 31, 2013 and 2012.

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' annual results of operations by approximately $19 million (2012 – $18 million) and Hydro One Networks' distribution business' annual results of operations by approximately $10 million (2012 – $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 derivative instruments 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 in existence as at December 31, 2013 or 2012.

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 years ended December 31, 2013 or 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 years ended December 31, 2013 and 2012 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Unrealized loss (gain) on hedged debt	(8)	(14)
Unrealized loss (gain) on fair value interest-rate swaps	8	14
Net unrealized loss (gain)	–	–

At December 31, 2013, Hydro One had $750 million (2012 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $12 million (2012 – $19 million). During the years ended December 31, 2013 and 2012, 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. At December 31, 2013 and 2012, 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 single customer. At December 31, 2013 and 2012, there was no significant accounts receivable balance due from any single customer.

At December 31, 2013, the Company's provision for bad debts was $36 million (2012 – $23 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2013, approximately 4% of the Company's net accounts receivable were aged more than 60 days (2012 – 3%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; 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 marked-to-market position on the measurement date. The Company would offset the positive market values against negative values with the same counterparty only 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 December 31, 2013, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $14 million (2012 – $22 million). At December 31, 2013, 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 three of the four counterparties accounted for more than 10% of the total credit exposure of derivative contracts.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, the revolving standby credit facility of $1,500 million, and by holding Province of Ontario Floating-Rate Notes. The short-term liquidity under the Commercial Paper Program, the holding of Province of Ontario Floating-Rate Notes and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2013, accounts payable and accrued liabilities in the amount of $795 million (2012 – $722 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2013, Hydro One had issued long-term debt in the principal amount of $9,045 million (2012 – $8,460 million). Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	**Principal Outstanding on Long-term Debt** *(millions of Canadian dollars)*	**Interest Payments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	750	422	3.1
2 years	550	398	2.8
3 years	500	372	4.3
4 years	600	361	5.2
5 years	750	330	2.8
	3,150	1,883	3.6
6 – 10 years	900	1,470	3.6
Over 10 years	4,995	4,281	5.5
	9,045	7,634	4.7

14. CAPITAL MANAGEMENT

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

The Company considers its capital structure to consist of shareholder's equity, preferred shares, long-term debt, and cash and cash equivalents. At December 31, 2013 and 2012, the Company's capital structure was as follows:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Long-term debt payable within one year	756	600
Less: cash and cash equivalents	565	195
	191	405
Long-term debt	8,301	7,879
Preferred shares	323	323
Common shares	3,314	3,314
Retained earnings	3,787	3,202
	7,101	6,516
Total capital	15,916	15,123

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2013 and 2012, Hydro One was in compliance with all of these covenants and limitations.

15. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (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 supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

The OMERS Plan

Hydro One contributions to the OMERS plan for the year ended December 31, 2013 were $2 million (2012 – $2 million). Company contributions payable at December 31, 2013 and included in accrued liabilities on the Consolidated Balance Sheets were $0.2 million (2012 – $0.2 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS plan, as indicated in OMERS's most recently available annual report for the year ended December 31, 2012.

At December 31, 2012, the OMERS plan was 85.6% funded, with an unfunded liability of $9,924 million. This unfunded liability will likely result in future payments by participating employers and members. Hydro One future contributions could be increased substantially if other entities withdraw from the plan.

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-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2013 of $160 million (2012 – $163 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2013 pensionable earnings. Estimated annual Pension Plan contributions for 2014 are approximately $160 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (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 is December 31.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	6,507	5,461	1,459	1,206
Current service cost	170	123	40	29
Interest cost	278	285	63	63
Reciprocal transfers	1	1	–	–
Benefits paid	(317)	(291)	(44)	(42)
Net actuarial loss (gain)	(63)	928	13	203
Projected benefit obligation, end of year	6,576	6,507	1,531	1,459
Change in plan assets				
Fair value of plan assets, beginning of year	4,992	4,682	–	–
Actual return on plan assets	887	425	–	–
Reciprocal transfers	1	1	–	–
Benefits paid	(317)	(291)	–	–
Employer contributions	160	163	–	–
Employee contributions	30	27	–	–
Administrative expenses	(22)	(15)	–	–
Fair value of plan assets, end of year	5,731	4,992	–	–
Unfunded status	845	1,515	1,531	1,459

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

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Accrued liabilities	–	–	43	43
Pension benefit liability	845	1,515	–	–
Post-retirement and post-employment benefit liability	–	–	1,488	1,416
Unfunded status	845	1,515	1,531	1,459

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for 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 (millions of Canadian dollars)	**2013**	**2012**
PBO	6,576	6,507
ABO	5,998	6,074
Fair value of plan assets	5,731	4,992

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2013 (2012 – 82%). On a PBO basis, the Pension Plan was funded at 87% at December 31, 2013 (2012 – 77%). 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 table provides the components of the net periodic benefit costs for the years ended December 31, 2013 and 2012 for the Pension Plan:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Current service cost, net of employee contributions	141	96
Interest cost	278	285
Expected return on plan assets, net of expenses	(309)	(289)
Actuarial loss amortization	175	112
Prior service cost amortization	2	3
Net periodic benefit costs	287	207
Charged to results of operations[1]	72	76

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2013, pension costs of $160 million (2012 – $163 million) were attributed to labour, of which $72 million (2012 – $76 million) was charged to operations, and $88 million (2012 – $87 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2013 and 2012 for the post-retirement and post-employment plans:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Current service cost, net of employee contributions	40	30
Interest cost	63	63
Actuarial loss amortization	27	8
Prior service cost amortization	3	3
Net periodic benefit costs	133	104
Charged to results of operations	58	48

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2013 and 2012:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2013**	**2012**	**2013**	**2012**
Significant assumptions:				
Weighted average discount rate	4.75%	4.25%	4.75%	4.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends[1]	–	–	4.39%	4.39%

[1] 6.81% per annum in 2014, grading down to 4.39% per annum in and after 2031 (2012 – 6.91% in 2013, grading down to 4.39% per annum in and after 2031)

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2013 and 2012. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	**2013**	**2012**
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.25%	6.25%
Weighted average discount rate	4.25%	5.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	11	11
Post-retirement and Post-Employment Benefits:		
Weighted average discount rate	4.25%	5.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	11	11
Rate of increase in health care cost trends[1]	4.39%	4.41%

[1] 6.91% per annum in 2013, grading down to 4.39% per annum in and after 2031 (2012 – 7.03% in 2012, grading down to 4.41% per annum in and after 2031)

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third party bond yield curve corresponding to each duration. The yield curve is based on AA long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2013 and 2012 is as follows:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Projected benefit obligation:		
Effect of 1% increase in health care cost trends	258	246
Effect of 1% decrease in health care cost trends	(200)	(191)

The effect of 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2013 and 2012 is as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Service cost and interest cost:		
Effect of 1% increase in health care cost trends	21	17
Effect of 1% decrease in health care cost trends	(16)	(13)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2013 and 2012:

December 31, 2013				**December 31, 2012**			
Life expectancy at 65 for a member currently at				**Life expectancy at 65 for a member currently at**			
Age 65		**Age 45**		**Age 65**		**Age 45**	
Male	Female	Male	Female	Male	Female	Male	Female
23	25	24	26	20	22	21	23

Estimated Future Benefit Payments

At December 31, 2013, estimated future benefit payments by the Company to Plan participants were:

(millions of Canadian dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2014	310	54
2015	319	57
2016	327	59
2017	335	62
2018	343	65
2019 through to 2023	1,698	370
Total estimated future benefit payments through to 2023	3,332	667

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs 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 table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Pension Benefits:		
Actuarial loss (gain) for the year	(619)	807
Actuarial loss amortization	(175)	(112)
Prior service cost amortization	(2)	(3)
	(796)	692
Post-Retirement and Post-Employment Benefits:		
Actuarial loss for the year	13	203
Actuarial loss amortization	(27)	(8)
Prior service cost amortization	(3)	(3)
	(17)	192

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2013 and 2012:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Pension Benefits:		
Prior service cost	3	5
Actuarial loss	842	1,510
	845	1,515
Post-Retirement and Post-Employment Benefits:		
Prior service cost	2	5
Actuarial loss	306	315
	308	320

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Prior service cost	2	2	2	3
Actuarial loss	103	175	15	17
	105	177	17	20

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

At December 31, 2013, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	67.8
Debt securities	35.0	32.2
Other [1]	5.0	0.0
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2013, the Pension Plan held $15 million of Hydro One corporate bonds (2012 – $20 million) and $217 million of debt securities of the Province (2012 – $243 million).

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, 2013 and 2012. 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, 2013 and 2012, there were no significant concentrations (defined as greater than 10% 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 derivative instruments by transacting only with financial institutions rated at least "A+" by Standard and Poor's, Dominion Bond Rating Service, and Fitch Ratings, and "A1" by Moody's Investors Service Inc., and also by utilizing exposure limits to each counterparty and ensuring that exposure is diversified across counterparties. 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 tables present the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2013 and 2012:

December 31, 2013 (millions of Canadian dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	1	16	117	134
Cash and cash equivalents	150	–	–	150
Short-term securities	–	180	–	180
Real estate	–	–	2	2
Corporate shares – Canadian	943	–	–	943
Corporate shares – Foreign	2,708	–	–	2,708
Bonds and debentures – Canadian	–	1,416	–	1,416
Bonds and debentures – Foreign	–	186	–	186
Total fair value of plan assets[1]	3,802	1,798	119	5,719

[1] At December 31, 2013, the total fair value of Pension Plan assets excludes $19 million of interest and dividends receivable, and $7 million relating to accruals for pension administration expense.

December 31, 2012 (millions of Canadian dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	2	15	104	121
Cash and cash equivalents	125	–	–	125
Short-term securities	–	100	–	100
Real estate	–	–	2	2
Corporate shares – Canadian	920	–	–	920
Corporate shares – Foreign	2,077	–	–	2,077
Bonds and debentures – Canadian	–	1,643	–	1,643
Total fair value of plan assets[1]	3,124	1,758	106	4,988

[1] At December 31, 2012, the total fair value of Pension Plan assets excludes $16 million of interest and dividends receivable, $4 million relating to accruals for pending sales transactions, and $8 million relating to accruals for pension administration expense.

See Note 13 – Fair Value of Financial Instruments and Risk Management 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 years ended December 31, 2013 and 2012. 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.

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Fair value, beginning of year	106	167
Realized and unrealized gains	23	5
Purchases	–	6
Sales and disbursements	(10)	(72)
Fair value, end of year	119	106

There have been no material transfers into or out of Level 3 of the fair value hierarchy.

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 private equity investments. 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 includes 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 investments in the holding companies are valued using net asset values reported by the fund manager. Real estate investments are 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.

16. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2013 and 2012:

Year ended December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	197	52	249
Interest accretion	9	1	10
Expenditures	(2)	(14)	(16)
Revaluation adjustment	(3)	26	23
Environmental liabilities, December 31	201	65	266
Less: current portion	15	12	27
	186	53	239

Year ended December 31, 2012 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	199	58	257
Interest accretion	9	2	11
Expenditures	(8)	(10)	(18)
Revaluation adjustment	(3)	2	(1)
Environmental liabilities, December 31	197	52	249
Less: current portion	13	9	22
	184	43	227

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	237	68	305
Less: discounting accumulated liabilities to present value	36	3	39
Discounted environmental liabilities	201	65	266

December 31, 2012 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	233	54	287
Less: discounting accumulated liabilities to present value	36	2	38
Discounted environmental liabilities	197	52	249

At December 31, 2013, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2014	27
2015	28
2016	35
2017	23
2018	22
Thereafter	170
	305

At December 31, 2013, of the total estimated future environmental expenditures, $237 million relates to PCBs (2012 – $233 million) and $68 million relates to LAR (2012 – $54 million).

Hydro One records a liability for the estimated future expenditures for the contaminated LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.3% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting the expectation that future environmental costs will be recoverable in rates.

PCBs

In September 2008, Environment Canada published regulations governing the management, storage and disposal of PCBs, enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under these regulations and Hydro One's approved end-of-use extension, PCBs in concentrations of 500 parts per million (ppm) or more have to be disposed of by the end of 2014, with the exception of specifically exempted equipment, and PCBs in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts, must be disposed of by the end of 2025. Management judges that the Company currently has very few PCB-contaminated assets in excess of 500 ppm. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $237 million. These expenditures are expected to be incurred over the period from 2014 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2013 to reduce the PCB environmental liability by $3 million (2012 – $3 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $68 million. These expenditures are expected to be incurred over the period from 2014 to 2022. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2013 to increase the LAR environmental liability by $26 million (2012 – $2 million).

17. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's AROs represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. AROs are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2013, Hydro One had recorded AROs of $14 million (2012 – $15 million), consisting of $7 million (2012 – $7 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $7 million (2012 – $8 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal and there have been no significant expenditures associated with these obligations in 2013.

18. SHARE CAPITAL

Preferred Shares

The Company has 12,920,000 issued and outstanding 5.5% cumulative preferred shares with a redemption value of $25 per share or $323 million total value. The Company is authorized to issue an unlimited number of 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 the redemption 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. Hydro One may elect, without condition, to pay all or part of the 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 at December 31, 2013. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

Common Shares

The Company has 100,000 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Common share dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial conditions, cash requirements, and other relevant factors, such as industry practice and shareholder expectations.

Earnings per Share

Earnings per share is calculated as net income for the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

19. DIVIDENDS

In 2013, preferred share dividends in the amount of $18 million (2012 – $18 million) and common share dividends in the amount of $200 million (2012 – $352 million) were declared.

20. 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.

Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues include $1,509 million (2012 – $1,474 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues include $127 million (2012 – $127 million) related to this program. Hydro One also receives revenues related to the supply of electricity to remote northern communities from the IESO. Distribution revenues include $33 million (2012 – $28 million) related to these services.

In 2013, Hydro One purchased power in the amount of $2,477 million (2012 – $2,392 million) from the IESO-administered electricity market; $15 million (2012 – $10 million) from OPG; and $8 million (2012 – $7 million) from power contracts administered by 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 transmitters. In 2013, Hydro One incurred $12 million (2012 – $11 million) in OEB fees.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2013, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $9 million (2012 – $10 million), 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 in 2013 (2012 – $2 million).

The OPA funds substantially all of the Company's conservation and demand management programs. The funding includes program costs, incentives, and management fees. In 2013, Hydro One received $34 million (2012 – $39 million) from the OPA related to these programs.

Hydro One pays a $5 million annual fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

PILs and payments in lieu of property taxes are paid to the OEFC, and dividends are paid 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 interest free and settled in cash.

At December 31, 2013, the Company held $250 million in Province of Ontario Floating-Rate Notes with a fair value of $251 million (2012 – $251 million).

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

December 31 (millions of Canadian dollars)	**2013**	**2012**
Due from related parties	197	154
Due to related parties[1]	(230)	(261)
Investment	251	251

[1] Included in due to related parties at December 31, 2013 are amounts owing to the IESO in respect of power purchases of $217 million (2012 – $199 million).

21. CONSOLIDATED STATEMENTS OF CASH FLOWS

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

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Accounts receivable	(78)	(30)
Due from related parties	(43)	2
Materials and supplies	–	2
Other assets	(5)	(4)
Accounts payable	(60)	(5)
Accrued liabilities	150	10
Due to related parties	(31)	(85)
Accrued interest	5	10
Long-term accounts payable and other liabilities	(11)	13
Post-retirement and post-employment benefit liability	84	56
	11	(31)

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Consolidated Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Capital investments in property, plant and equipment	(1,312)	(1,363)
Net change in accruals included in capital investments in property, plant and equipment	(21)	(10)
Capital expenditures – property, plant and equipment	(1,333)	(1,373)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Capital investments in intangible assets	(82)	(91)
Net change in accruals included in capital investments in intangible assets	3	1
Capital expenditures – intangible assets	(79)	(90)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Net interest paid	395	411
PILs	138	197

22. 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 the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company 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. In 2013, the Company paid approximately $2 million (2012 – $1 million) in respect of these consents. If the Company cannot obtain the required consents, 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 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 the Company is not able to recover them in future rate orders.

23. COMMITMENTS

Agreement with Inergi LP (Inergi)

In 2002, Inergi, an affiliate of Capgemini Canada Inc., began providing services to Hydro One, including business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The current agreement with Inergi will expire in February 2015.

At December 31, 2013, the annual commitments under the Inergi agreement are as follows: 2014 – $130 million; 2015 – $22 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 December 31, 2013, 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 (2012 – $325 million), and on behalf of two distributors using guarantees of $1 million (2012 – $1 million). In addition, as at December 31, 2013, the Company has provided letters of credit in the amount of $21 million (2012 – $22 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 letters of credit plus the amount of the parental guarantees.

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 eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these 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 letters of credit. At December 31, 2013, Hydro One had letters of credit of $127 million (2012 – $127 million) outstanding relating to retirement compensation arrangements.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have an average life of between one and five years with renewal options for periods ranging from one to 10 years included in some of the contracts. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions. There are no restrictions placed upon Hydro One by entering into these leases. Hydro One Networks and Hydro One Telecom are the principal entities concerned.

At December 31, the future minimum lease payments under non-cancellable operating leases were as follows:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Within one year	11	10
After one year but not more than five years	28	29
More than five years	9	14
	48	53

During the year ended December 31, 2013, the Company made lease payments totaling $11 million (2012 – $9 million).

24. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing electricity 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. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and provision for PILs from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Year ended December 31, 2013 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	1,529	4,484	61	6,074
Purchased power	–	3,020	–	3,020
Operation, maintenance and administration	375	672	59	1,106
Depreciation and amortization	327	340	9	676
Income (loss) before financing charges and provision for PILs	827	452	(7)	1,272
Financing charges				360
Income before provision for PILs				912
Capital investments	714	673	7	1,394

Year ended December 31, 2012 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	1,482	4,184	62	5,728
Purchased power	–	2,774	–	2,774
Operation, maintenance and administration	402	608	61	1,071
Depreciation and amortization	320	329	10	659
Income (loss) before financing charges and provision for PILs	760	473	(9)	1,224
Financing charges				358
Income before provision for PILs				866
Capital investments	776	671	7	1,454

Total Assets by Segment:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Total assets		
Transmission	11,846	11,586
Distribution	8,805	8,621
Other	974	604
	21,625	20,811

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

25. SUBSEQUENT EVENT

On January 29, 2014, Hydro One issued $50 million notes under its MTN Program, with a maturity date of January 29, 2064 and a coupon rate of 4.29%.

HYDRO ONE INC. 2012 FINANCIAL STATEMENTS

HYDRO ONE INC.
ANNUAL CONSOLIDATED FINANCIAL STATEMENTS

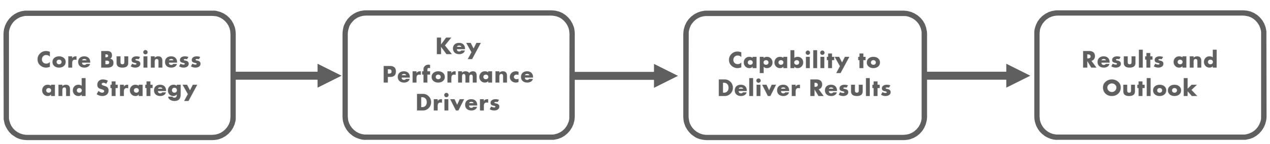
On January 1, 2012, Hydro One Inc. (Hydro One) adopted United States (US) Generally Accepted Accounting Principles (GAAP) as its approved basis for accounting and financial reporting. Comparative 2011 information is presented under US GAAP, unless otherwise noted. All amounts are in Canadian dollars.

The following discussion is based on our Consolidated Financial Statements for the years ended December 31, 2012 and 2011.

EXECUTIVE SUMMARY

We are wholly owned by the Province of Ontario (Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). Our mission and vision has been refined to recognize the unique role we play in the economy of the province and as a provider of critical infrastructure to all our customers. We strive to be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety; excellence; stewardship; and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial, transparent and which values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers. In 2012, we continued to focus on our core businesses and our commitment to our customers and made important contributions to the rebuilding of Ontario's core infrastructure while continuing to meet the requirements of the Green Energy Act (GEA).

We manage our business using the following framework:



Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic goals, which are discussed in the section "Our Strategy," encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; shareholder value; and productivity.

Key Performance Drivers

Performance drivers have been identified that relate to achieving certain of our company's strategic goals. We establish specific performance targets for each driver aimed at measuring the achievement of our strategic goals over time. For example, we track the duration of unplanned customer interruptions per delivery point as an indication of our commitment to provide a reliable transmission system for our customers. We measure transmission and distribution unit costs as an indication of our commitment to increasing productivity. These and other key performance drivers are included in our discussion of our performance measures in the section "Performance Measures and Targets."

Capability to Deliver Results

We continue to use a balanced scorecard approach as we strive to manage our performance and deliver results each and every year. In 2012, we set nine stretch targets and we met or exceeded five of them. In 2011, we met or exceeded 13 of 17 stretch targets. We exceeded our target for minimizing the duration of unplanned customer interruptions within our Transmission Business. Our performance with respect to productivity was on target in our subsidiary Hydro One Networks Inc.'s (Hydro One Networks) transmission and distribution businesses. Our ability to deliver results in each of our strategic areas is limited by risks inherent in our regulatory environment, our business, our workforce and in the economic environment. These risks, as well as our strategies to mitigate them, are discussed in the section "Risk Management and Risk Factors."

Results and Outlook

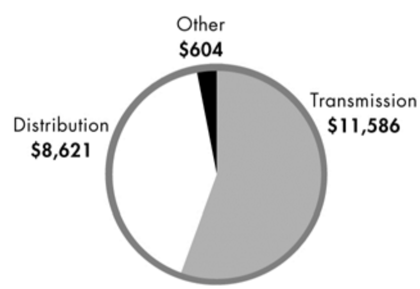
During 2012, our financial fundamentals remained strong with current year net income of $745 million. Our OEB-approved revenue requirement for our transmission business for 2012 was $1,418 million. Our 2011 distribution rates for Hydro One Networks continued unchanged throughout 2012, and its approved revenue requirement for 2011 was $1,218 million. Approved rates support the work programs required to sustain our critical infrastructure and invest in a sustainable electricity system that supports renewable and cleaner generation. We successfully issued $1,085 million in debt financing in 2012, the proceeds of which were used to fund the retirement of $600 million of debt maturing in the year and to fund a portion of our capital expenditures and other corporate requirements. A full discussion of our results of operations and financing activities can be found in the sections "Results of Operations" and "Liquidity and Capital Resources."

In 2012, we invested more than $1.4 billion in capital expenditures to improve system reliability and performance, address our aging power system, facilitate new generation and improve service to our customers. Capital expenditures for the next few years will include those required to build critical infrastructure identified in the Long-Term Energy Plan (LTEP), which is based on recommendations from the Ontario Power Authority (OPA), and expenditures to address aging infrastructure. Our future capital expenditures are more fully described in the section "Future Capital Expenditures."

OVERVIEW

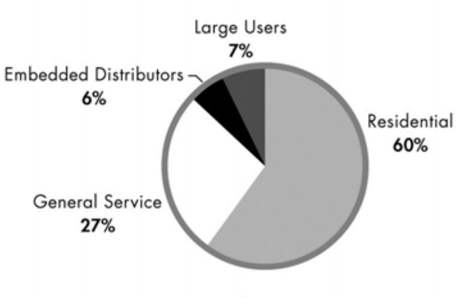
Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our subsidiary Hydro One Networks. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2012, we earned total transmission revenues of $1,482 million, primarily by transmitting approximately 141 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and it is linked to five adjoining jurisdictions through 26 interconnections, through which we can accommodate imports of about 4,800 MW and exports of approximately 6,000 MW of electricity. In terms of assets, our Transmission Business is our largest business segment, representing approximately 56% of our total assets at December 31, 2012.



Total Assets
December 31, 2012
(CAD $ millions)

Distribution



2012 Distribution Revenues

Our consolidated distribution system is the largest in Ontario and it spans roughly 75% of the province. We serve approximately 1.4 million rural and urban customers and 440 large user customers. Our subsidiary Hydro One Remote Communities Inc. (Hydro One Remote Communities) operates small, regulated generation and distribution systems in a number of remote communities across northern Ontario that are not connected to Ontario's electricity grid. In 2012, we earned total distribution revenues of $4,184 million. As illustrated in the accompanying chart, over half of our distribution revenues were earned from our residential customers. At December 31, 2012, our Distribution Business assets represented approximately 41% of our total assets.

Other

In 2012, our Other business segment contributed revenues of $62 million, and had assets of $604 million at December 31, 2012, representing 3% of our total assets. This segment primarily represents the operations of our wholly-owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario.

Our Strategy

Our corporate strategy is based on our mission and vision and our values. Our mission and vision is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs:

Health and safety: Nothing is more important than the health and safety of our employees, those who work on our property, and the public.

Excellence: We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and cost-effective service, with integrity.

Stewardship: We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.

Innovation: We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that are inextricably linked. They drive the fulfillment of our mission and vision.

Creating an injury-free workplace and maintaining public safety. Health and safety must be integrated into all that we do. We must continue to create a passion for preventing injury. We will strengthen our already strong safety culture through our Journey to Zero initiative and achieve world-class results. We will implement the internationally recognized health and safety management system, ISO 18001, to identify health and safety risks, priorities and mitigation in order to further drive our safety culture. We will continue to reinforce that nothing is more important than the health and safety of our employees.

Satisfying our customers. We will meet our commitments, make customers our focus in our planning, communicate effectively, coordinate across lines of business, and maximize opportunities to improve our corporate image. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs and behaviours.

Continuous innovation. Innovation represents one of our core values and is critical to achieving our mission and vision. Over the next two decades, we will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers with more capability to manage their power costs. The Advanced Distribution System (ADS) is a key element in our investment in innovation and will improve operation of our distribution assets and deliver further value to our customers.

Building and maintaining reliable, cost-effective transmission and distribution systems. Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on: incorporating ADS technology to provide greater visibility; increasing control and improving customer service; supporting the connection of renewable energy sources; seeking efficiencies through leveraging technology and operational experience from our transmission system; providing reliable and cost-effective service over a diverse geography; and pursuing commercial arrangements that are anticipated to arise from the rationalization of Ontario's distribution sector.

Protecting and sustaining the environment for future generations. Consistent with our value of stewardship, we play a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use. We will engage our customers further regarding how we manage our sustainability obligations and activities on their behalf.

Employee engagement. We believe our primary strength is the capability of our people. In order to sustain this advantage, we must address the issues of corporate culture, labour demographics, diversity, development of critical core competencies and skill and knowledge retention. Our labour strategy should enable us to make significant gains in the areas of labour flexibility, productivity improvement and cost reduction.

Maintaining a commercial culture that increases value for our shareholder. We are committed to keeping rates as low as possible for our customers, and delivering income and dividends to our shareholder. This is possible through our focus on reducing costs, managing our assets effectively and increasing productivity. We will explore and pursue opportunities to increase the revenue-earning potential of our company by leveraging existing assets, technologies, capabilities and the geographic presence of our company.

Achieving productivity improvements and cost-effectiveness. To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our shareholder.

We recognize the pivotal role innovation will play in building a smart electricity grid that supports a clean environment for Ontario. We are committed to becoming the industry leader in putting innovative solutions to work for the well-being of Ontario's economy and its residents.

Performance Measures and Targets

We target and measure our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we maintain a focus on our strategic objectives and take mitigating actions as required. In 2012, we met or exceeded five of nine stretch targets. Overall, we are making progress towards achieving many of our strategic goals.

Achieving productivity improvements and cost-effectiveness

One of our strategic objectives is to increase productivity through efficiency improvements and effective management of costs. The measures for this objective for 2012 were transmission unit cost and distribution unit cost.

For 2012, we measured for transmission unit cost the capital expenditures and operation, maintenance and administration costs per dollar of gross in-service assets (expressed as a percentage). For distribution unit cost, the measure is capital expenditures and operation, maintenance and administration costs per kilometre of line ($'000/km) due to the length of line required to connect our rural customers. Our objective with our ongoing work and investment program is to maintain and improve our assets and monitor our productivity year-over-year. Our transmission unit cost target was set at 10.1% and we met this target. The distribution unit cost target was set at $11,000 per kilometre of line and we also met this target.

Building and maintaining reliable, cost-effective transmission and distribution systems

We continue to build and retain public confidence and trust in our operations, as stewards of Ontario's electricity grid. In 2012, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for customers in a safe, reliable and efficient fashion. We are conscious that commercial customers of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration when interruptions occur. Transmission and distribution reliability is measured through the duration of customer interruptions.

For the duration of unplanned customer interruptions within our Transmission Business, the target for 2012 was 10 minutes per delivery point. We more than met this target.

For the Hydro One Networks distribution business, the target for 2012 for the duration of customer interruptions was set at 6.7 hours per customer. We did not meet this target.

Satisfying our customers

Customer satisfaction measures the degree to which our transmission and distribution customers are satisfied with the service they receive from our company. Customer satisfaction is based on the results of customer surveys conducted on our behalf by independent third parties. In 2012, for transmission customers we targeted a customer satisfaction rate of 90%, but did not meet this target. For our distribution customers, we targeted a satisfaction rate of 86%, and we met this target.

Employee engagement

We continue to focus efforts on increasing employee engagement throughout the company. An engaged workforce is one in which employees embrace the corporate values of safety, stewardship, excellence and innovation. The process of measuring and improving such engagement began in 2008 by means of an employee engagement survey administered by an independent third-party expert. Our goal is to improve the grand mean score year-over-year. The target of improving the grand mean score to 4.06 (out of 5) in 2012 was not met.

Maintaining a commercial culture that increases value for our shareholder

Achievement of strong financial performance is measured by a performance measure of targeted level of net income after tax. Our target was $643 million net income after tax and we exceeded our target.

Creating an injury-free workplace and maintaining public safety

The safety of our employees is paramount. In 2012, we used medical attentions, defined as injuries that require treatment by a medical practitioner (beyond first aid), as the performance measure for this strategic objective. The medical attentions measure reflects incidents that are reported to the Workplace Safety and Insurance Board and is calculated as the number of attentions per 200,000 hours worked. In 2012, Hydro One set a target of no higher than 2.2 attentions per 200,000 hours worked. In an effort to achieve this target, we engaged in a number of activities, such as: continued emphasis on improving health and safety through face-to-face sessions; continuation of our Journey to Zero initiative; better monitoring of mandatory skills and safety training; an enhanced driver training/evaluation program; and field coaching to increase the expectations from supervisors and staff. The number of attentions in 2012 improved by 35% compared to the number in 2011 but was still slightly higher than our target for 2012.

REGULATION

Our electricity transmission and distribution businesses are licenced and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the province-wide uniform transmission rates (UTRs) approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our Distribution Business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory accounts over specified timeframes.

Electricity Rates

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on both a two-tiered electricity pricing structure, with seasonal consumption thresholds, and a three-tiered electricity pricing structure with Time of Use (TOU) thresholds. The majority of our RPP customers are now on TOU billing. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the OPA. Prices are reviewed by the OEB every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period.

We started migrating our customers to TOU rates in 2010 and the majority of our customers were transitioned to TOU rates by the end of 2011. We received an exemption from the OEB, effective until December 31, 2014, from implementing mandatory TOU pricing for approximately 120,000 customers that are currently out of reach of our smart meter telecommunications infrastructure.

Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators by the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998*. The IESO is responsible for overseeing and operating the wholesale market as well as ensuring the reliability of the integrated power system.

Transmission Rates

The IESO facilitates payments to us based on the Ontario UTRs approved by the OEB for all transmitters across Ontario.

On May 19, 2010, we submitted our application for 2011 and 2012 transmission rates in continued support of our aging critical infrastructure and supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the GEA. This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012, which represented estimated rate increases of 15.7% and 9.8%, respectively, or 1.2% and 0.7% on an average customer's monthly bill.

On December 23, 2010, the OEB issued its decision, which resulted in a revenue requirement effective January 1, 2011 of $1,346 million for 2011 and $1,658 million for 2012, reflecting transmission rate changes of approximately 7% in 2011 and 26% in 2012, or 0.5% and 2%, respectively, on an average customer's total bill. Our 2012 revenue requirement was impacted by the OEB directing us to adopt a cost capitalization policy consistent with International Financial Reporting Standards (IFRS). This specific accounting revision resulted in an increased revenue requirement of about $200 million for 2012.

Consistent with an approval from the Ontario Securities Commission (OSC) to adopt US GAAP for our external financial reporting and securities filings, on July 15, 2011 we filed a Motion to Vary the OEB's 2012 rate decision. Our application sought approval to adopt US GAAP as a basis for regulatory accounting and rate setting in place of the OEB's approved modified IFRS basis. On November 23, 2011, the OEB approved the use of US GAAP by our Transmission Business, which resulted in the reversal of the $200 million adjustment that was made by the OEB in its December 2010 rate decision.

On December 1, 2011, we submitted to the OEB a draft 2012 transmission revenue requirement that reflects the approved adoption of US GAAP for rate-setting purposes as well as the OEB-directed update to 2012 cost-of-capital parameters. On December 20, 2011, the proposed $1,418 million 2012 revenue requirement was approved by the OEB along with new 2012 UTRs effective January 1, 2012. The new rates resulted in an approximate 8% transmission rate increase, or 0.6% on an average customer's total bill. The adoption of US GAAP in lieu of modified IFRS as a basis for rate setting decreased the approved rates by about 15%.

To achieve the necessary funding in support of aging critical infrastructure and investments, we submitted a cost-of-service rate application to the OEB for our 2013 and 2014 transmission rates on May 28, 2012. The application sought OEB approval for revenue requirement increases of approximately 0.6% and 9.1% in 2013 and 2014, respectively, or estimated increases of 0% in 2013 and 0.7% in 2014, on an average customer's total bill. A settlement conference was held in October 2012, where Hydro One Networks and the intervenors reached an agreement, settling all issues apart from Export Transmission Service. This is anticipated to be settled in early 2013 but is not expected to affect our company's results of operations. The settlement agreement was reviewed and approved by the OEB on November 8, 2012. On November 30, 2012, we submitted a draft rate order, which includes revenue requirements of approximately $1,438 million and $1,528 million for 2013 and 2014, respectively. For the transmission portion of the bill, this represents no change from existing 2012 OEB-approved rate levels in 2013 and a 5.8% increase in 2014. On an average customer total bill basis, this represents increases of nil for 2013 and 0.5% for 2014. On December 20, 2012, the OEB issued a final Rate Order, approving Hydro One Networks' 2013 transmission revenue requirement for use in setting the 2013 Ontario UTRs.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for our approved distribution rates, purchased power costs and other approved regulatory charges. Substantially all of our purchased power costs and other approved regulatory charges are settled through the IESO, which facilitates payments to other parties such as generators, the Ontario Electricity Financial Corporation (OEFC) and itself.

In 2006, the OEB established a multi-year electricity distribution rate-setting plan whereby a distributor's rates are set via a cost-of-service rebasing application followed by an Incentive Regulation Mechanism (IRM) that uses a formulaic approach to establish rates for the next three years. In 2012, the OEB issued a new regulatory framework that included three rate-setting methods available to distributors (see "Renewed Regulatory Framework").

Hydro One Networks

On July 13, 2009, our subsidiary Hydro One Networks filed a cost-of-service application with the OEB for 2010 and 2011 distribution rates.

On April 9, 2010, the OEB released its decision approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters.

On November 15, 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. The lowering of the return on equity (ROE) produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011, or 3.4% on an average (i.e. consuming 800 kWh per month) customer's total bill.

On March 23, 2012, the OEB approved our request for Hydro One Networks' distribution business to adopt US GAAP for rate setting and regulatory accounting and reporting. Hydro One Networks did not seek a distribution cost-of-service rate adjustment for 2012 and rates continued unchanged at 2011 levels.

On June 15, 2012, Hydro One Networks filed evidence in support of its application for 2013 distribution rates on the basis of the OEB's 3rd Generation IRM process. Hydro One Networks and intervenors subsequently reached a settlement and submitted a settlement agreement to the OEB. On December 14, 2012, the OEB issued its decision accepting the agreement as filed. On December 20, 2012, the OEB issued a final Rate Order. The distribution rate of an average residential customer will increase by approximately 1.3% in 2013, or by 0.4% when considering total bill impacts. In addition, the Retail Transmission Service Rates adjustment, which was accepted in the Settlement, will bring the total bill increase in 2013 to approximately 1.5%.

Hydro One Brampton Networks

On June 30, 2010, our subsidiary Hydro One Brampton Networks submitted its 2011 cost-of-service application, which was subsequently adjusted in September to reflect the optional deferral of the adoption of modified IFRS until January 1, 2012, consistent with a decision by the Canadian Accounting Standards Board (AcSB). The AcSB later extended the optional deferral to January 1, 2014 and Hydro One Brampton Networks has decided to exercise this option.

Following another adjustment to the application in November 2010, the revenue requirement was approximately $63 million. On April 4, 2011, the OEB issued a decision that approved a revenue requirement of $59.5 million for 2011. The revised rates were approved with an effective date of January 1, 2011 and an implementation date of May 1, 2011. Included in the rates is an amount of $1.52 per month per metered customer for smart meters and approval of a GEA funding adder of $0.02 per month per metered customer. The new rates result in a total bill increase for an average customer (i.e. consuming 800 kWh per month) of approximately 0.5%.

On September 15, 2011, Hydro One Brampton Networks filed an application for 2012 rates on the basis of the OEB's 3rd Generation IRM process. On December 22, 2011, the OEB issued its decision and on December 31, 2011, the OEB declared Hydro One Brampton Networks' existing rates interim as of January 1, 2011. On January 5, 2012, the OEB released a decision that resulted in a reduction in rates of approximately 13.2%, or a 1.7% reduction on the average customer's total bill in the year. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates.

On August 3, 2012, Hydro One Brampton Networks filed an application for 2013 rates on the basis of the OEB's 3rd Generation IRM process, requesting new distribution rates effective January 1, 2013. Hydro One Brampton Networks subsequently amended its rate application and on December 6, 2012, the OEB approved the amended application. The rate impact on the distribution component associated with a typical residential customer was an increase of approximately 0.3%, or less than 0.1% on the customer's total bill.

Hydro One Remote Communities

On October 15, 2010, Hydro One Remote Communities filed an application for 2011 distribution rates on the basis of the OEB's 3rd Generation IRM. The application sought approval for an increase of approximately 0.4% to basic rates for the distribution and generation of electricity effective May 1, 2011. On March 28, 2011, the OEB approved the application. The overall impact of the new rates on an average (i.e. consuming 800 kWh per month) residential customer's total bill was marginal.

On November 25, 2011, Hydro One Remote Communities filed its application for 2012 distribution rates on the basis of the OEB's 3rd Generation IRM. On March 22, 2012, the OEB issued its decision approving a rate increase of 1.08% effective May 1, 2012, representing an increase of about $1 on an average residential customer's monthly bill.

Consistent with the OEB's decision affirming the use of US GAAP for rate-setting purposes by Hydro One Networks' transmission and distribution businesses, we made a similar request to use US GAAP for Hydro One Remote Communities. On April 3, 2012, the OEB approved the request to use US GAAP as the basis for rate setting within Hydro One Remote Communities effective January 1, 2012.

On September 17, 2012, Hydro One Remote Communities filed a cost-of-service application for 2013 rates to be effective May 1, 2013. If approved as filed, the electricity rate of an average customer will increase by 3.5% in 2013. In its rate application, Hydro One Remote Communities also requested approval to establish a Rural and Remote Rate Protection of $35 million in 2013. The OEB Hearing and decision are anticipated to occur in the first quarter of 2013.

Recent Industry Developments

Long-Term Energy Plan

On November 23, 2010, the Ministry of Energy released Ontario's LTEP, which sets out the province's expected electricity needs until 2030 and supports the continued procurement of new, cleaner generation. The LTEP addresses seven key areas: demand; supply; conservation; transmission; aboriginal communities; capital investments; and electricity prices. On February 17, 2011, the Province issued a Supply Mix Directive that required the OPA to prepare a 20-year Integrated Power System Plan (IPSP) to meet the goals set out in the LTEP. On May 9, 2011, the OPA announced that it was beginning consultations to update Ontario's IPSP and issued the *IPSP Planning and Consultation Overview* document. On June 17, 2011, we submitted our comments on the IPSP, as requested of stakeholders by the OPA. Stakeholder comments will form part of the evidence when the OPA submits the revised IPSP to the OEB for its review.

On February 28, 2011, the OEB issued a decision amending Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy to the OEB. The licencee amendment requires Hydro One Networks to develop and either seek approvals for, or implement, specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy in accordance with recommendations from the OPA. In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transformer stations noted in the licence to accommodate small-scale renewable generation. Six of these upgrades have been completed and we are currently anticipating that one additional station upgrade will be placed in service in 2013. Alternative solutions have been identified for the other three upgrades. 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 (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. As a result, the recovery of the seven station upgrades was restricted. We charged $17 million to operation, maintenance and administration expense in 2012 and charged $19 million to operation, maintenance and administration expense in 2011, in respect of these projects.

In June 2011, the OPA recommended the scope and timing of the project to re-conductor two circuits between Sarnia and London, our West of London Transmission Upgrade Project, with a required in-service date of December 2014. This project is needed to satisfy government policy relating to the incorporation of 10,700 MW of non-hydroelectric renewable generation resources by 2018. On November 8, 2012, the OEB issued a decision approving our Section 92, Leave to Construct, application for this project. In October 2011, the OPA recommended the scope and timing of the Southwestern Ontario Reactive Compensation Priority Project, recommending that we install a Static Var Compensator (SVC) at our Milton Switching Station to increase the capability of our Bruce to Milton Line. An OPA recommendation regarding the construction of a new transmission line west of the City of London is not expected in the foreseeable future.

Framework for Transmission Development Plans

On August 26, 2010, the OEB released its new policy entitled *Framework for Transmission Project Development Plans*. This policy sets out a framework for new transmission investment in Ontario by introducing competition for transmission development through an open process. On March 29, 2011, the Minister of Energy expressed the Province's interest in the OEB commencing a transmitter designation process for the East-West Tie Line. The East-West Tie Project is the first transmission network line expansion covered under the new competitive approach. The proposed route is a 400 km, 230 kV double-circuit line between its transformer stations at Wawa in the east and Lakehead in the west. The target in-service date, set by the OPA in its report issued June 30, 2011, is 2017. The East-West Tie LP, an equally-shared partnership of three entities including our company, obtained a transmission licence on May 31, 2012, and is participating in the East-West Tie Project bid process.

The OEB adopted a two-phase process for the East-West Tie proceeding. On July 12, 2012, the OEB issued its Phase 1 decision and order, thus concluding Phase 1 of the proceeding by finalizing various filing requirements and process issues and directing registered transmitters to file their applications for designation by January 4, 2013. The proceeding is now in Phase 2 and the OEB received six applications for designation from the registered transmitters in the proceeding, including one from the East-West Tie LP. The timeline for Phase 2, which will take the form of a written hearing, has not yet been set.

Renewed Regulatory Framework

On December 17, 2010, the OEB initiated a coordinated consultation process for the development of a renewed regulatory framework for electricity distributors and transmitters. On October 18, 2012, the OEB issued its report *A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, marking the completion of its consultation process. The report identified three rate-setting models available to provide choices suitable for distributors having varying capital requirements: a 4th Generation IRM, which builds on the current 3rd Generation model by adding one year to the IRM period; a Custom IRM, which involves rate setting based on a five-year forecast of a distributor's revenue requirement and sales volume; and an Annual Incentive Rate-setting Index method, which involves annual adjustment of rates by a simple price cap index formula. The report also provided information on performance measurement, continuous improvement and implementation of the new framework.

Four working groups were established to provide expert assistance to review and advise the OEB's staff on proposals regarding certain implementation matters: Asset Redefinition and Regional Infrastructure Planning Process; Distribution Network Investment Planning; Performance, Benchmarking, and Rate Adjustment Indices; and Smart Grid. Hydro One Networks is represented on all four groups. Working group meetings began in November 2012 and are scheduled through February 2013. Consultations will conclude with the issuance of filing requirements and guidance, code amendments, and/or supplemental Board policies in support of the new framework. The OEB is expecting that policies will be largely implemented in time for the 2014 rate year. We are currently assessing the rate-setting methods available.

OEB Transmission and Distribution System Codes

Under the Transmission System Code, the transmitter covers the initial pooling of the costs of enabler lines, with generators paying their pro-rata share when ready to connect, based on generator capacity.

Under the Distribution System Code (DSC), there are three classes of distribution assets associated with the connection of renewable energy generation: connection assets, expansion assets, and renewable enabling improvements. Generators that connect directly to a distributor's system pay the costs of connection assets, while distributors fund: all expansion costs identified in a plan; other generator-requested expansion costs up to a cap of $90,000/MW per project (generator pays the rest); and all renewable enabling improvements.

In 2011, the OEB granted us an exemption from mandatory DSC timelines for the connection of micro-embedded generation facilities. The OEB decision increased the timeline for processing indirect connections that require a site assessment and approved amendments to the conditions that must be met before we are required to connect micro-embedded generation facilities to our distribution system. On August 3, 2012, Hydro One Networks applied to the OEB for an extension of the exemption and on November 8, 2012, the OEB granted the extension for a period ending August 3, 2013, or six months after the conclusion of its consultation on micro-embedded generation issues, whichever is earlier.

Ontario Clean Energy Benefit

Effective January 1, 2011, the Province introduced the *Ontario Clean Energy Benefit Act, 2010,* which is designed to assist Ontario electricity consumers through the transition to a cleaner electricity system. Under this Act, eligible residential, farm and small business consumers receive a 10% benefit with respect to the total cost of electricity on their bills, including tax, for a five-year period. This benefit is applied to customers' electricity costs for each billing period. Effective September 1, 2012, the 10% rebate is applied only to the first 3,000 kWh of electricity consumed per month.

Revenue Decoupling for Distributors

In 2010, the OEB initiated a consultation process to examine the revenue adjustment and cost recovery mechanisms available to electricity and natural gas distributors to address revenue erosion resulting from unforecasted changes in volume of energy sold. These mechanisms are commonly referred to as "revenue decoupling" mechanisms as each involves some means of disconnecting the link between the volume of energy consumed by customers and the recovery by energy distributors of their approved revenue requirement.

On November 26, 2012, the OEB initiated a project to complete the work begun on revenue decoupling for electricity and natural gas distributors. The OEB will coordinate its consideration of revenue decoupling with the new rate-setting policies proposed in the renewed regulatory framework for electricity. The OEB will examine how best to address changes in demand, including potential declines in average use. This consultation will review the options for potential revenue decoupling in addition to the existing lost revenue decoupling mechanism (i.e. the Lost Revenue Adjustment Mechanism or LRAM). The OEB expects to release a draft policy in early 2013. The OEB will solicit stakeholder comments in writing before finalizing the policy.

Distribution Sector Consolidation

On April 13, 2012, the Province announced it was launching a comprehensive review of Ontario's electricity sector to explore options to improve efficiencies, including local distribution companies (LDCs) consolidation. As a result, the Province created the Ontario Distribution Sector Review Panel (Panel). On December 13, 2012, the Panel released its report, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, with recommendations for electricity sector consolidation. This report recommends that the 73 LDCs comprising the focus of the report be consolidated into eight to 12 larger regional electricity distributors within a two-year timeframe. Specifically, it recommends there be two regional distributors in northern Ontario and between six and ten regional distributors in southern Ontario with a minimum of 400,000 customers each. Given our company's position as the largest LDC, the report recommends that Hydro One Networks be given unambiguous direction to lead and engage in the discussion of the merger of distribution assets with the appropriate interested utilities on a commercial basis. At present, the Province is reviewing the report and assessing the recommendations.

FIT and microFIT

On October 1, 2009, the OPA launched its Feed-in Tariff (FIT) Program which is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy and waterpower up to 50 MW.

On March 22, 2012, the Province announced the results of its two-year FIT Program Review, including recommended changes to reflect input received from stakeholders. The OPA implemented these recommendations and re-launched its microFIT program on July 12, 2012. The revised program encourages greater community and aboriginal participation and the protection of agricultural lands. In August 2012, the OPA began to release approvals allowing microFIT projects to proceed. On December 14, 2012, the OPA announced that it will award up to 200 MW of Small FIT applications, received between December 14, 2012 and January 18, 2013, for renewable energy projects with a proposed capacity between ten and 500 kilowatts. The OPA is not accepting Large FIT applications at this time. The timing for the Large FIT project application window will be communicated once details are finalized.

Conservation and Demand Management (CDM)

The OPA continues to be responsible for coordinating the delivery and funding of Ontario's CDM programs. Our CDM programs funded through the OPA in 2012 amounted to approximately $25 million, compared to $15 million in 2011. These programs included: the Peaksaver Program; the Low Income Home Assistance Program; Appliance Retirement and Exchange Events; and the Process and System Upgrade Incentive Program.

The *Ontario Energy Board Act, 1998*, as amended by the GEA, provides direction to the OEB to take steps to establish CDM targets to be met by LDCs and other licencees. A province-wide CDM target for Ontario's LDCs was set in 2010. The two key CDM targets for LDCs over the four-year period beginning January 1, 2011 were to collectively reduce 1,330 MW of provincial summer peak demand and to provide 6,000 GWh of cumulative energy savings. The OEB issued its CDM Code for Electricity Distributors (CDM Code) on September 16, 2010 and on November 12, 2010, it issued final CDM targets to each LDC. Our company was allocated a 259 MW reduction of provincial peak demand and a 1,320 GWh reduction of electricity consumption, representing, respectively, 19.5% and 22.0% of the total target savings established for all LDCs. The CDM Code also set out the conditions and rules that LDCs are required to follow if they choose to use OEB-approved CDM programs to meet their CDM targets.

On April 26, 2012, the OEB issued its CDM guidelines for all electricity distributors. One key change is that savings associated with TOU pricing are eligible to be counted towards the CDM targets. Savings will be evaluated by the OPA for the entire province and then allocated to each distributor. The other key change is the establishment of the LRAM variance account, which captures the variance between the level of CDM included in a distributor's load forecast and the verifiable results of impacts of CDM activities undertaken between 2011 and 2014 for both OPA-contracted and OEB-approved CDM programs.

On September 28, 2012 and September 30, 2012, in accordance with the CDM Code, Hydro One Brampton Networks and Hydro One Networks, respectively, filed their 2011 Annual CDM Reports with the OEB. Our combined results for 2011 were 40 MW in peak demand savings, representing 15.6% of our target, and 99 GWh of annual energy savings. These energy savings will produce 388 GWh towards our target, representing 29.4% of our cumulative target. We anticipate meeting our 2014 cumulative demand and energy savings targets.

On December 21, 2012, the Minister of Energy issued a directive to the OPA to extend funding for its CDM programs for one additional year, to December 31, 2015. This extension aims to provide added stability, support the momentum of province-wide programs and ensure that projects with longer completion times can continue to participate in key conservation initiatives. This extension will also provide an opportunity for the OPA and LDCs to collaboratively work to strengthen the current framework and deliver innovative programs that support Ontario families and businesses. The OPA will be reaching out to distributors to further solicit insight and advice on the implementation of this extension.

Advanced Distribution System

The *Energy Conservation Responsibility Act, 2006* further broadened the objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario. In 2007, the Province appointed the IESO as the interim smart meter entity that would oversee the collection and management of data from installed smart meters. LDCs, including our distribution businesses, are accountable for the deployment of smart meter infrastructure and related communications technology to meet minimum regulatory requirements, as well as the implementation of TOU rates.

In 2011, we carried out a number of studies on advanced distribution technologies and initiated the Smart Zone Pilot Project in the Owen Sound area. The Smart Zone Pilot consists of testing and demonstrating power system equipment, IT systems and communication systems that will be required to help facilitate the connection of a large number of Distributed Generation (DG) connections to our distribution system. In 2012, we successfully completed the deployment of the Distribution Management System (DMS) within the Owen Sound pilot area. This integrates the Network Management System, the Outage Response Management System and field devices. Further releases of the ADS will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses. All releases leverage a core infrastructure and build on each other, and as pilot elements are proven, business cases will be developed for the provincial roll out which will ultimately comprise the ADS.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (millions of dollars)	2012	2011	$ Change	% Change
Transmission	1,482	1,389	93	7
Distribution	4,184	4,019	165	4
Other	62	63	(1)	(2)
	5,728	5,471	257	5
Average annual Ontario 60-minute peak demand *(MW)*[1]	21,132	21,166	(34)	-
Distribution – units distributed to customers *(TWh)*[1]	29.2	29.2	-	-

[1] System-related statistics are preliminary.

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. 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 $93 million, or 7%, compared to 2011. On December 23, 2010, the OEB rendered its decision on our 2011 and 2012 transmission rate application. On December 20, 2011, the OEB approved new transmission tariff rates, effective January 1, 2012, which reflected higher in-service assets and the use of US GAAP as our basis for rate setting. The decisions resulted in higher transmission revenues of $106 million for the year ended December 31, 2012, and the average peak demand for 2012 resulted in a slight increase of $3 million, compared to the prior year.

Increases were partially offset by a $9 million reduction in revenue following the completion of recovery of a transmission regulatory account effective December 31, 2011, a $6 million reduction in transmission-related external revenues and a $1 million reduction associated with other OEB-approved regulatory accounts.

Distribution

Our consolidated Distribution Business consists of the separate distribution businesses of our subsidiaries Hydro One Networks, Hydro One Brampton Networks, and Hydro One Remote Communities. Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our consolidated Distribution Business. Accordingly, our 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 for late payments.

Our 2012 distribution revenues were higher by $165 million, or 4%, compared to 2011. The increase was primarily due to the recovery of higher purchased power costs of $146 million, as described below under "Purchased Power." Our distribution revenues were also higher by $18 million due to our placement of new ADS and smart meter investments in service. Given that these investments relate to new technologies, they are currently recovered through separate rate mechanisms.

Distribution revenues for the year reflect additional external revenues of $7 million, an increase in Hydro One Remote Communities' revenues of $2 million and a $1 million increase associated with OEB-approved regulatory accounts. These increases were partially offset by a $7 million reduction due to lower energy consumption, resulting primarily from the milder winter we experienced in 2012 compared to 2011, and by a decrease of $2 million in Hydro One Brampton Networks' distribution tariff revenues.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of electricity delivered to customers within our distribution service territories. These costs comprise the wholesale commodity cost of energy, the IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on 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.

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
November 1, 2012	1,000	750	7.4	8.7

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
November 1, 2012	11.8	9.9	6.3

Purchased power costs increased by $146 million, or 6%, to $2,774 million for the year, compared to 2011. The increase in our purchased power costs was primarily due to an increase of $118 million resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers, a $33 million increase resulting from the OEB transmission rate decision effective January 1, 2012 that affected the transmission charges levied by the IESO, and a $7 million increase related to higher electricity demand. The effect of these increases was partially offset by an $11 million reduction compared to 2011 in wholesale market service charges levied by the IESO, which include certain costs for operating the transmission grid, and a $1 million decrease resulting from lower purchased power costs for customers who are not eligible for the RPP.

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:

Year ended December 31 (millions of dollars)	**2012**	**2011**	**$ Change**	**% Change**
Transmission	402	422	(20)	(5)
Distribution	608	609	(1)	-
Other	61	61	-	-
	1,071	1,092	(21)	(2)

Our company continues to focus on managing its costs, resulting in a decrease in total operation, maintenance and administration expenditures in 2012, compared to 2011, while continuing to substantially complete the planned work programs for both our transmission and distribution businesses.

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $20 million, or 5%, in 2012 compared to 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 lower by $33 million compared to last year mainly due to: lower demand for station-related corrective maintenance, particularly for power equipment; lower demand for underground cable corrective maintenance; and reduced autotransformer remediation work. We also incurred lower expenditures compared to last year related to the OPA's recommendation to increase short circuit and/or transformer capacity at a number of our transmission stations to enable the connection of small renewable projects, for which recovery is restricted (see "Regulation – Long-Term Energy Plan"). Most of this work has now been completed. Expenditures in support of our transmission system increased by $13 million, compared to 2011, due to a redirection of resources from our Distribution Business, partially offset by management cost reduction initiatives.

Distribution

Operation, maintenance and administration expenditures required to maintain our low-voltage distribution system decreased slightly by $1 million compared to last year. Our work program expenditures decreased by $5 million mainly due to decreased power restoration expenditures resulting from overall lower storm activity in Ontario in 2012 compared to 2011. Reductions also resulted from lower lines maintenance requirements, partially offset by increased requirements within our forestry program resulting from higher tree densities experienced this year. Our expenditures in support of our distribution system increased by $4 million mainly due to spending in support of the Customer Information System (CIS) phase of our entity-wide information system replacement and improvement project. The impact of this increase was partially offset by cost reduction initiatives and a redirection of resources in support of our Transmission Business.

Depreciation and Amortization

Depreciation and amortization expense increased by $43 million, or 7%, in 2012, compared to 2011. This increase was attributable to higher depreciation expense of $40 million, when compared to 2011, primarily related to our placement of new assets in service consistent with our ongoing capital work program. Slightly higher asset removal costs of $3 million contributed the remainder of the variance from the prior year.

Financing Charges

Financing charges increased by $14 million, or 4%, to $358 million for 2012 compared to 2011. Higher financing costs were mainly due to an increased average level of debt and partially offset by a lower average effective interest rate.

Provision for Payments in Lieu of Corporate Income Taxes (PILs)

The provision for PILs decreased by $29 million, or 19%, to $121 million in 2012, compared to 2011. This decrease primarily resulted from a reduction in the statutory tax rate from 28.25% to 26.50%, changes in net temporary differences, and an increase in research and development tax credits related to our ADS project. This reduction was partially offset by the impact of higher levels of pre-tax income compared to 2011.

Net Income

Net income of $745 million was higher by $104 million, or 16%, than our comparable 2011 results. Higher revenues reflect the recovery of prior year investments which are now in service and which will improve the province's electricity system. Our net income was also positively impacted by lower operation, maintenance and administration expenditures resulting from cost-effectively managing the work program within our Transmission Business and by lower PILs resulting from a lower combined federal and provincial statutory income tax rate compared to 2011. In addition, our 2012 net income reflects higher depreciation expense resulting from our placement of new assets in service, consistent with our increased capital work program, and increased financing charges reflecting our higher average level of debt.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2011 through December 31, 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.

(millions of dollars)	2012				2011			
Quarter ended	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**
Total revenue	1,435	1,466	1,359	1,468	1,359	1,384	1,268	1,460
Net income	165	201	169	210	120	167	142	212
Net income to common shareholder	160	197	164	206	115	163	137	208

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.

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, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (millions of dollars)	**2012**	**2011**
Operating activities	1,285	1,407
Financing activities		
Long-term debt issued	1,085	700
Long-term debt retired	(600)	(500)
Dividends paid	(370)	(168)
Investing activities		
Capital expenditures	(1,454)	(1,447)
Other financing and investing activities	21	64
Net change in cash and cash equivalents	(33)	56

Operating Activities

Net cash from operating activities decreased by $122 million to $1,285 million in 2012, compared to 2011. The decrease was primarily due to changes in accrued liabilities related to customer prepayments, and a reduction in taxes payable, resulting from a tax payment made in the first quarter of 2012 related to the 2011 taxation year, as well as the timing of tax installment payments in 2012, compared to 2011. The decrease was partly offset by higher 2012 net income, compared to 2011.

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 a long-term investment in Province of Ontario Floating-Rate Notes of $250 million (with a fair value of $251 million at December 31, 2012). The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

At December 31, 2012, we had $8,460 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2013 and 2062. 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. At December 31, 2012, $1,515 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
Standard & Poor's (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 at December 31, 2012.

In 2012, we successfully issued $1,085 million in cost-effective long-term debt under our MTN Program, consisting of $300 million issued in the first quarter, $425 million issued in the second quarter, $310 million issued in the third quarter, and $50 million issued in the fourth quarter of 2012. In the third quarter of 2012, we also called and redeemed $600 million of our long-term debt, prior to its maturity date of November 15, 2012.

In 2011, we issued $700 million in long-term debt under our MTN Program, consisting of $300 million issued in the first quarter, $300 million issued in the third quarter, and $100 million issued in the fourth quarter of 2011. In 2011, we also repaid $500 million in maturing long-term debt, $250 million in the first quarter and $250 million in the fourth quarter.

We had no short-term notes outstanding as at December 31, 2012 or December 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 2012, we paid dividends to the Province in the amount of $370 million, consisting of $352 million in common dividends and $18 million in preferred dividends. In 2011, we paid dividends in the amount of $168 million, consisting of $150 million in common dividends and $18 million in preferred dividends.

In 2012, cash dividends per common share were $3,523, compared to $1,500 per common share in 2011. Cash dividends per preferred share were $1.375 in each of 2012 and 2011.

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.

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:

Year ended December 31 (millions of dollars)	**2012**	**2011**	**$ Change**	**% Change**
Transmission	776	810	(34)	(4)
Distribution	671	628	43	7
Other	7	9	(2)	(22)
	1,454	1,447	7	-

Transmission

Transmission capital expenditures decreased by $34 million, or 4%, to $776 million in 2012, compared to 2011. Investments to expand and reinforce our transmission system were $313 million, representing a decrease of $103 million from 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 in 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 SVCs at our Nanticoke, Detweiler, Porcupine and Kirkland Lake transformer stations. Also contributing to the reduction in expenditures were lower expenditures in 2012 related to our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliability in the Woodstock area, and our Bruce to Milton Transmission Reinforcement Project connecting refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. These projects were successfully put into service in March and May of this year, respectively. The impact of the reductions in expenditures in both periods was partially offset by increases in our expenditures resulting from load customer connection and local area supply projects progressing into their build phases, and investments in our transformer stations related to the ADS Project, which supports clean DG connected to our distribution system consistent with the GEA.

On June 18, 2012, our subsidiary Hydro One Networks entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively known as the Saugeen Ojibway Nation (SON). The agreement contemplates a new Limited Partnership (LP) to hold only the lines and related land rights of our 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 in late 2013. Under the terms of our agreement, the SON will be eligible to purchase a non-controlling equity interest in the LP at fair value. The LP is anticipated to become a rate-regulated entity under the jurisdiction of the OEB. Transfer of our 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. On December 18, 2012, the SON, Hydro One Networks and Hydro One signed a Letter Agreement in connection with the establishment of the LP. The Letter Agreement addresses, among other things, the terms of the LP Agreement to be entered into on closing and the terms on which Hydro One Networks will operate the Bruce to Milton Line on behalf of the LP. The closing is conditional on certain regulatory approvals and tax rulings.

Our local area supply project expenditures include investments in our Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure to increase the load supply capacity and to ensure reliability of supply to customers in the area. The project successfully went into service on December 21, 2012. 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.

Significant expenditures within our load customer connection projects include investments to build our Commerce Way Transformer Station, a new load supply station in the City of Woodstock that was partially put into service on December 19, 2012. This project will provide additional transformation and line capacity to address load growth issues in the Woodstock area.

Expenditures to sustain our existing transmission system were $392 million in 2012, representing an increase of $57 million compared to 2011. During the year, we made significant investments in the refurbishment and replacement of end-of-life equipment, including end-of-life oil circuit breakers, switches, insulators and protections at our Abitibi Canyon switching station, and deteriorated autotransformers at our Trafalgar and Claireville transformer stations. Of these projects, the autotransformer at our Trafalgar transformer station and one of two at our Claireville transformer station were successfully put into service this year. During the year, we also experienced an increase in replacements for end-of-life protection and control equipment.

Our other transmission capital expenditures were $71 million in 2012, representing an increase of $12 million compared to 2011. The majority of these increased expenditures were related to fleet acquisitions and to information technology (IT) investments.

Distribution

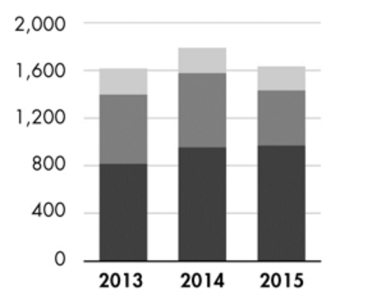
Our distribution capital expenditures increased by $43 million, or 7%, to $671 million in 2012, compared to 2011. Capital investments to expand and reinforce our distribution network were $284 million in 2012, representing an increase of $15 million compared to 2011. We experienced increases in 2012 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 will protect distributed generators from power interruption and is anticipated to improve outage restoration, reduce construction and ongoing maintenance costs, and reduce power loss as it flows across the electricity grid. 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 to 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 network were $245 million in 2012, representing an increase of $5 million compared to 2011. The increase in our sustainment program was primarily impacted by increased work accomplished within our lines and distribution station refurbishment programs, as well as higher expenditures related to the strategic purchase of power transformers compared to the prior year. These impacts were partially offset by lower storm restoration work given lower storm activity in 2012 compared to two major storms in Ontario in 2011.

Other distribution capital expenditures were $142 million in 2012, representing an increase of $23 million, compared to 2011. The majority of these expenditures were related to the CIS phase of our enterprise-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. Productivity savings are anticipated to result from performance improvements, consolidation of systems, and decommissioning of over a dozen legacy systems.

Future Capital Expenditures

Our capital expenditures for 2013 are budgeted at approximately $1,600 million. Our 2013 capital budgets for our transmission and distribution businesses are about $1,000 million and $600 million, respectively. Consolidated capital expenditures are expected to be approximately $1,750 million in 2014 and $1,650 million in 2015. These expenditure levels reflect meeting the sustainment requirements of our aging infrastructure. Our sustainment program is expected to be approximately $800 million in 2013, $950 million in 2014 and $1,000 million in 2015. 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 expected to be approximately $600 million in 2013, $600 million in 2014, and $450 million in 2015. These development investments also reflect customer demand work. Other capital expenditures are expected to be approximately $200 million in each of 2013, 2014 and 2015. These expenditures include investments to replace our end-of-life customer billing system and smaller projects related to the continued realization of increased productivity from our enterprise-wide SAP information system.



Future Capital Expenditures
(CAD $ millions)

Transmission

Transmission capital expenditures include significant investments to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. Our investment plan includes sustainment investments to replace end-of-life air blast circuit breakers and switchgear, high-voltage underground cable, and aging power transformers and to comply with North American Electricity Reliability Corporation cyber security requirements. These sustaining investments are necessary to ensure that we continue to meet all regulatory, compliance, safety and environmental objectives.

Major capital investments include our Oshawa Area Transformer Station Project to install additional auto-transformer capacity at our proposed Clarington Transformer Station, for which the OPA has requested that Hydro One develop an implementation plan and initiate work. Planning and environmental studies are currently being undertaken for this project. Investments also include our Midtown Electricity Infrastructure Renewal Project that will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west, our SVC installation to be completed at our Milton station, and our project to rebuild the switching station at our Hearn Transformer Station, which is expected to be completed by 2014. Transmission investments for ADS and requirements to enable DG are also included in the investment plan. The Hearn Transformer Station Project, when combined with four other transformer station upgrades, will collectively enable up to 600 MW of new transmission capacity.

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. On April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transformer stations. These upgrades are substantially complete. Expenditures for these upgrades have been recorded within operation, maintenance and administration (see "Regulation – Long-Term Energy Plan"). Two of the three priority specified transmission projects are reflected in our budgeted capital expenditures. The West of London Transmission Upgrade Project generally requires restringing conductor on existing towers along an existing right-of-way and will enable the connection of additional renewable generation in the west of London area. The Southwestern Ontario Reactive Compensation Priority Project will increase the transmission capability of the Bruce transmission system. We are awaiting direction on the third priority project from the OPA (see "Regulation – Long-Term Energy Plan").

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 expansions 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.

The actual timing and expenditures of many development projects are uncertain as they are dependent upon: various approvals including OEB leave to construct approvals and environmental assessment approvals; negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities. Projects are also dependent on the timing and level of generator contributions for enabling facilities.

Distribution

Distribution capital expenditures include investments to support the sustainment of our capital infrastructure. Our core work will continue to focus on the performance of our aging distribution asset base in order to improve system reliability. There are continuing investments to replace end-of-life equipment and components, implement ADS as part of this renewal and a focus on wood pole replacements to maintain reliability. In addition, we will continue to address customer demand projects through connectivity for DG, the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

Distribution development expenditures over the period are primarily related to the development of an ADS system and related grid modernization standards, customer demand work such as connections and upgrades, work to facilitate DG connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. During the 2013 and 2014 periods, we expect to manage a significant number of projects throughout the province to address load growth and the stress on our system components.

DG expenditures are based on our estimate of the number of anticipated connections, which have been reduced based on the experience gained since 2009 and changes that have occurred to the FIT Program. The budget only reflects expenditures for projects with FIT and microFIT Program contracts from the OPA that are expected to connect to our distribution system.

In 2013, the ADS Project will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses.

Summary of Contractual Obligations and Other Commercial Commitments

There are no off-balance-sheet arrangements that have, or are reasonably likely to have, a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments.

December 31, 2012 (millions of dollars)	**Total**	**2013**	**2014/2015**	**2016/2017**	**After 2017**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	8,460	600	1,300	1,100	5,460
Long-term debt – interest payments	7,336	410	735	651	5,540
Pension[1]	330	158	172	-	-
Environmental and asset retirement obligations[2]	313	30	73	40	170
Inergi LP (Inergi) outsourcing agreement[3]	287	136	151	-	-
Operating lease commitments	53	10	15	14	14
Total Contractual Obligations[4]	16,779	1,344	2,446	1,805	11,184
Other Commercial Commitments *(by year of expiry)*					
Bank line[5]	1,250	-	-	1,250	-
Letters of credit[6]	150	150	-	-	-
Guarantees[6]	326	326	-	-	-
Total Other Commercial Commitments	1,726	476	-	1,250	-

1 Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 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 were approximately $160 million. 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.

2 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.

3 On March 1, 2002, Inergi began providing a range of services to us for a ten-year period, including IT, customer care, supply chain and certain human resources and finance services. On May 1, 2010, consistent with the terms of the contract, our company extended the Master Services Agreement with Inergi for a further three-year period, to expire on February 28, 2015. Given the complexities involved, we have begun developing a plan of action for end-of-term and anticipate working towards a request for proposal in 2013. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

4 In addition, our company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these agreements is considered individually material, and the majority do not extend beyond December 31, 2013.

5 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.

6 We currently have outstanding bank letters of credit of $127 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 began providing prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. As at December 31, 2012, we provided letters of credit to the IESO in the amount of $22 million to meet our current prudential requirement. The other $1 million 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 $0.7 million.

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 purchase 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 PILs and some of our property taxes, which are paid or payable to the 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

Effect of Load on Revenue

Our load, based on normal weather patterns, is expected to marginally decline in 2013 due to the impact of CDM and embedded generation, partially offset by load growth associated with economic growth in all sectors of the Ontario economy. Overall load growth due to the economy alone is forecasted to be approximately 1.3%, with the commercial and industrial sectors slightly outperforming the residential sector. The load impacts of CDM and embedded generation are expected to have a negative impact on load growth of approximately 1.1% and 0.3%, respectively. On the whole, our load is expected to decline by about 0.1% in 2013. Our approved revenue requirement for 2013 has taken the expected load decline into account. A reduction in load, beyond our load forecast included in our approved revenue requirement, would negatively impact our financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements upon which our rates are based. The first component impacted by interest rates is our ROE. The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. All other things being equal, we estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our ROE would reduce Hydro One Networks' transmission and distribution businesses' results of operations by approximately $19 million and $10 million, respectively. As interest rates decline, there is more risk of a decline in our net income. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs and Commodity Pricing

In support of our ongoing work programs, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, general outline agreements, and vendor alliances and we also manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts on our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counterparties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund capital expenditures or meet debt maturity repayments and other liquidity requirements (see "Risk Management and Risk Factors – Risk Associated with Arranging Debt Financing"). We rely on debt financing through our MTN Program and Commercial Paper Program. Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities as at December 31, 2012, which is comprised of a $1,250 million syndicated bank line of credit and the holding of $250 million of Province of Ontario Floating-Rate Notes. In 2012, we continued issuing sufficient cost-effective debt financing through the MTN Program in the Canadian capital markets and we arranged sufficient available liquidity. Economic conditions were challenging in 2012 and we expect they will remain challenging in 2013.

Pension

In 2012, we contributed approximately $160 million to our pension plan and incurred $207 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 $160 million for 2013 and 2014, 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 9.19% in 2012. Our pension obligation is impacted by interest rates. The 1% decrease in the discount rate, from 5.25% at December 31, 2011 to 4.25% at December 31, 2012, resulted in an increase in the pension obligation of $862 million and an increase to our post-retirement and post-employment benefit obligation of $241 million. No new benefits were introduced and over the last number of years benefits have been reduced through re-negotiations with certain of our unions as well as our management employees.

RISK MANAGEMENT AND RISK FACTORS

We have an Enterprise Risk Management (ERM) Program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic goals. Our ERM program helps us to better understand uncertainty and its potential impact on our strategic goals. It sets out the uniform principles, processes and criteria for identifying, assessing, evaluating, treating, monitoring and communicating risks across all lines of business. It supports our Board of Directors' corporate governance needs and the due diligence responsibilities of senior management.

While our philosophy is that risk management is the responsibility of all employees, the Board of Directors annually reviews our company's risk tolerances, risk management policies, processes and accountabilities. Twice per year, the Board of Directors reviews our risk profile, which is the list of key risks prepared by senior management, that represents the greatest threats to meeting our strategic objectives. The Audit and Finance Committee of our Board of Directors annually reviews the status of our internal control framework.

Our President and Chief Executive Officer (CEO) has ultimate accountability for risk management. Our Leadership Team provides senior management oversight of our risk portfolio and our risk management processes. The leadership team provides direction on the evolution of these processes and identifies priority areas of focus for risk assessment and mitigation planning.

Our Chief Administration Officer and Chief Financial Officer (CAO and CFO) is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. The CAO and CFO has specific accountability for ensuring that enterprise risk management processes are established, properly documented and maintained by our company.

Our senior managers, line and functional managers are responsible for managing risks within the scope of their authority and accountability. Risk acceptance or mitigation decisions are made within the risk tolerances specified by the head of the subsidiary or function.

The CAO and CFO provides support to the Audit and Finance Committee of our Board of Directors, the President and CEO, the senior management team and key managers within our company. This support includes developing risk management frameworks, policies and processes, introducing and promoting new techniques, establishing risk tolerances, preparing annual corporate risk profiles, maintaining a registry of key business risks and facilitating risk assessments across our company. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems. Starting in 2013, our Board of Directors has taken on an enhanced role in our governance structure. Each committee of the Board of Directors will take accountability for reviewing specific risks of our company.

Key elements of our ERM Program enable us to identify, assess and monitor our risks effectively. These include having an ERM policy and framework which communicates our philosophy and process for risk management across our company. A discussion of risks is an integral part of each line of business' planning documents on an annual basis. Risk identification is also considered as part of each business case for investments. Finally, discrete risk assessments and workshops are performed for specific lines of business, key projects and various profiles, such as customer relationships and regulatory compliance.
In order to drive consistency throughout our risk identification and risk management processes, we use a standard list of risk sources known as our risk universe. These sources are maintained in a single database that provides a consistent basis for risk identification and classification and serves as a repository for our risk assessments. All risk assessments in our company start with this risk universe. We also use standard risk criteria, which establish the metrics and terminology used for assessing and communicating on risks, and help ensure a consistent basis for our risk assessments and risk evaluations across all lines of business. Risk criteria include formally established risk tolerances and standard scales for assessing the probability of a risk materializing and the strength of controls in place to mitigate them.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008, the Province made a declaration removing certain powers from our company's Directors pertaining to the off-shoring of jobs under the outsourcing arrangement with Inergi. In 2009, the Province required our company, among other entities, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Our credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of Hydro One's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, including any potential outcomes arising out of the recommendations of the Ontario Distribution Sector Review Panel's report, the Province's ownership of Ontario Power Generation Inc., and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us which could have a material adverse effect on our business.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, our net income for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively affected by successful CDM programs. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

We expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets, particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

In Ontario, the Market Rules mandate that we comply with the reliability standards established by North American Electric Reliability Corporation and Northeast Power Coordinating Council Inc. As a result, we will be required to comply with the Federal Energy Regulatory Commission's definition of "bulk electric system" unless we are granted an exemption which will allow the application of the new definition in a cost-effective manner. We will look for recovery for costs incurred in meeting the definition in our rates; however an adverse decision on an exemption for recovery of costs could have an adverse effect on our company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt which mature between 2013 and 2016, including $600 million maturing in 2013 and $750 million maturing in 2014. We plan to incur capital expenditures of approximately $1.6 billion in 2013 and $1.8 billion in 2014. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our company.

Risk Associated with Transmission Projects

The amount of power that can flow through transmission networks is constrained due to the physical characteristics of transmission lines and operating limitations. Within Ontario, new and expected generation facility connections, including those renewable energy generation facilities connecting as a result of the FIT program stemming from the GEA, and load growth have increased such that parts of our transmission and distribution systems are operating at or near capacity. These constraints or bottlenecks limit the ability of our network to reliably transmit power from new and existing generation sources (including expanded interconnections with neighbouring utilities) to load centres or meet customers' increasing loads. As a result, investments have been initiated to increase transmission capacity and enable the reliable delivery of power from existing and future generation sources to Ontario consumers.

In many cases, these investments are contingent upon one or more of the following approvals and/or processes: environmental approval(s); receipt of OEB approvals which can include expropriation; and appropriate consultation processes with First Nations and Métis. Obtaining OEB and/or environmental assessment approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments which could adversely affect transmission reliability and/or our service quality, both of which could have a material adverse effect on our company.

With the introduction on August 26, 2010 of the OEB's competitive transmission project development planning process, in the absence of a government directive, all interested transmitters will be required to submit a bid to the OEB for identified enabler facilities and network enhancement projects. Historically, we would have been awarded such projects through our rates and Section 92, Leave to Construct, applications. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, bid costs are only recoverable by the successful proponent. This could have a material adverse effect on our company.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain equipment performance and provide reliable service quality. Our capital programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. However, if we are unable to carry out these plans in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

Workforce Demographic Risk

By the end of 2012, approximately 18% of our employees were eligible for retirement and by 2013 there could be up to 20% eligible to retire. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We are therefore focused on earlier identification and more rapid development of staff who demonstrate management potential. Moreover, we must also continue to advance our technical training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, it could have a material adverse effect on our business.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. Given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee, however, that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation (LAR) program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's PCB regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025, while our LAR expenditures are expected to be incurred over the period ending 2020. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities. Actual future expenditures may vary materially from the estimates used for the amount of the asset retirement obligation.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases.

We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our company.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex IT systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats and by providing company-wide awareness training to our personnel. We also engage the services of external experts to evaluate the security of our IT infrastructure and controls. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Upon occurrence, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on our company.

We are currently in the process of a planned phased replacement of key enterprise IT systems. The last phase of this project is underway and will replace our existing billing and customer system with a new CIS. With projects of this size and complexity, there is risk to the Company if the resulting solution encounters performance problems or calculation errors. Any such system problems could have a material adverse effect on our company. To mitigate this risk, extensive testing and user training is taking place. Testing includes performance, system integration, parallel billing (comparing legacy system bill calculation to the new system), and operational/business readiness. Since this system directly impacts our end customers, stringent test exit criteria must be met prior to placing it into production.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2011 and was filed in May 2012. Our company contributed $148 million in respect of 2011 and approximately $160 million in respect of 2012 to its pension plan to satisfy minimum funding requirements. An additional contribution of $3.8 million was also made in 2011 to complete the funding associated with the partial plan wind-up. Contributions beyond 2012 will depend on investment returns, changes in benefits and actuarial assumptions and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our company, and this risk may be exacerbated as the quantum of required pension contributions increase.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency-denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach. The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' net income by approximately $19 million and our Hydro One Networks' Distribution Business' net income by approximately $10 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest-rate swap agreements to mitigate elements of interest-rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counterparties. We do not trade in any energy derivatives. We do, however, have interest-rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlements Code. The failure to properly manage these risks could have a material adverse effect on our company.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals. Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost-efficient manner. Although we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 similar to a previous reduction affecting management staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2013 and the existing Society collective agreement will expire on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our company.

First Nation and Métis Claims Risk

Some of our current and proposed transmission and distribution lines may traverse lands over which First Nations and Métis have aboriginal, treaty or other legal claims. Although we have a recent history of successful negotiations and consultations with First Nations and Métis in Ontario, some communities and/or their citizens have expressed an increasing willingness to assert their claims through the courts, tribunals, or by direct action, which in turn can affect business activities. As a result, there exists uncertainty relating to business operations and project planning which could have an adverse effect on our company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves. Currently, OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy Reserves, we must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the First Nation, OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. However, we anticipate that the amount will exceed the approximately $943,000 that we paid in 2012. OEFC will continue to hold these assets until we are able to negotiate agreements with First Nations and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we amended and extended our outsourcing services agreement with Inergi, effectively renewing the arrangement until February 28, 2015. If the agreement with Inergi is terminated for any reason, we could be required to incur significant expenses to transfer to another service provider, which could have a material adverse effect on our business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks, which could have an adverse effect on our company.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated Financial Statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our Consolidated Financial Statements:

Regulatory Assets and Liabilities

At December 31, 2012, regulatory assets amounted to $3,127 million and these amounts principally relate to regulatory offsets to pension, deferred income tax, post-retirement and post-employment benefits and environmental liabilities, which are anticipated to be recovered through rates over time. We have also recorded regulatory liabilities amounting to $221 million as at December 31, 2012. These amounts pertain primarily to OEB deferral and variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the relevant amounts have been approved for inclusion in the rate-setting process by the OEB or if such approval is judged to be probable by management. If management judges that it is no longer probable that the OEB will include a regulatory item in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to satisfy obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of assets contaminated with PCB-laden mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work now and make assumptions for when the future expenditures will actually be incurred in order to generate future cash flow information. A long-term inflation assumption of 2% is used to express our current cost estimates as estimated future expenditures. Future estimated LAR expenditures are expected to be incurred over the period ending 2020 and are discounted using factors ranging from 3.57% to 4.87%, depending on the appropriate rate for the period when the particular obligation was recorded. Consistent with the current requirements of Environment Canada's PCB regulations, estimated future PCB remediation expenditures are expected to be incurred over the period ending 2025 and are discounted using factors ranging from 5.14% to 6.25%, depending on the appropriate rate in effect in the period when each obligation was originally recorded.

Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination; the number of assets to be inspected, tested and mitigated; oil volumes; contamination levels of equipment that may have PCBs; and the timing of work. All factors used in deriving our environmental liabilities represent management's best estimates based on our planned approach of meeting current legislative and regulatory requirements. These requirements include Environment Canada's regulations governing the management, storage and disposal of PCBs. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation estimates and the actual pattern of annual future cash flows may differ significantly from our current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Regulatory changes are reflected when enacted. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (the Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions in respect of 2012 were approximately $160 million, based on an actuarial valuation effective December 31, 2011. Contributions after 2014 will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the Consolidated Financial Statements on an accrual basis. The discount rate used to calculate the accrued benefit obligation, on an accrual accounting basis, is calculated differently from what would be used to determine the funding requirement, and is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2012 declined to 4.25% from 5.25% used at December 31, 2011, in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities for accounting purposes. We also record employee future benefit costs other than pension on an accrual accounting basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries. There were no changes in benefits afforded to employees.

The assumed return on pension plan assets of 6.25% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was 60% equities, 35% fixed income and 5% in alternative assets consisting of real estate and infrastructure. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the Fund's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. In the short term, the plan can experience aberrations in actual return. In 2012, the return on pension plan assets of 9.19% was higher than this long-term assumption and was higher than in 2011.

Yields on AA corporate bonds declined by approximately 80-100 basis points between December 31, 2011 and December 31, 2012. Based on the duration of the plan's liabilities, discount rates would be 4.25% per annum for each of the pension plan, the post-retirement benefit plan and the post-employment plan. The overall discount rate applied to all plans for liability accounting purposes as at December 31, 2012 was 4.25%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has decreased from 2.0% per annum as at December 31, 2011 to approximately 1.90% per annum as at December 31, 2012. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for liability valuation purposes as at December 31, 2012.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $17 million per year and an increase in the year-end obligation of about $246 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed and intangible assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as part of the cost of fixed and intangible assets.

Asset Impairment

Within our regulated businesses, carrying costs of our other assets are recovered in our revenue requirements and are included in rate base, where they earn a return. Such assets would need to be tested for impairment only in the event that the OEB disallowed recovery or if such a disallowance was judged to be probable. We periodically monitor the assets of our unregulated Telecom Business for indications of impairment. No asset impairments have been recorded to date within any of our businesses.

TRANSITION TO US GAAP

Accounting Framework for External Reporting

In 2011, the 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 Consolidated Financial Statements and accompanying notes as at, and for the year ended, December 31, 2012 have been prepared in accordance with US GAAP. These are our first US GAAP annual Consolidated Financial Statements. Our first US GAAP unaudited interim Consolidated Financial Statements were as at, and for the three months ended, March 31, 2012.

Our company's Consolidated Financial Statements were prepared in accordance with Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook until December 31, 2011. Canadian GAAP differs in some areas from US GAAP as disclosed in the reconciliation to US GAAP included in Note 24 to the annual Consolidated Financial Statements as at, and for the year ended, December 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 24 to our annual Consolidated Financial Statements for the year ended December 31, 2012. The accounting policies set out in the annual Consolidated Financial Statements for the year ended December 31, 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 IFRS basis. The OEB approved Hydro One Networks' request to adopt US GAAP for its regulated transmission and distribution 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. Our subsidiary Hydro One Brampton Networks has deferred its adoption of modified IFRS until the fiscal year beginning January 1, 2014, as allowed by the Canadian Accounting Standards Board. Currently, Hydro One Brampton Networks will continue to have its rates set based on Part V of the CICA Handbook until it begins reporting under modified IFRS.

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 2013, we will continue to 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 ongoing basis, as we have certain subsidiaries that are required to prepare their own separate financial statements in accordance with IFRS. IFRS training was also previously provided to our Audit and Finance Committee and senior executive management. In 2013, we will continue to monitor new IFRS accounting and reporting developments and emerging issues and will provide IFRS training to specific staff as applicable.

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 International Accounting Standards Board's (IASB) 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 IASB 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 (ICFR)

To optimize our customer service operations, we have started the final major phase of our planned SAP enterprise-wide information system by initiating our CIS Project. This new system will increase productivity by replacing multiple 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 system integration phase. Internal controls have been documented and will be tested for adequacy and effectiveness with any remediation effort to be completed prior to the go-live date in 2013. In addition to the benefits associated with our 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 Consolidated Financial Statements for the year ended December 31, 2012, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Based on the evaluation of the design and operation of our DC&P, our Certifying Officers concluded that our DC&P was effective as at December 31, 2012. Further, our Certifying Officers have also certified that our ICFRs have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of our company's ICFR, our Certifying Officers concluded that our ICFR was effective as at December 31, 2012.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2012, 2011 and 2010. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statements of Operations

Year ended December 31 (millions of dollars, except amounts per share)	**2012**	**2011**	**2010**[1]
Revenues	5,728	5,471	5,124
Net income	745	641	591
Basic and fully diluted earnings per common share	7,280	6,228	5,727
Cash dividends per common share	3,523	1,500	100
Cash dividends per preferred share	1.375	1.375	1.375

Consolidated Balance Sheets

December 31 (millions of dollars)	**2012**	**2011**	**2010**
Total assets	20,811	18,836	17,344
Total long-term debt	8,479	8,008	7,783

1 Based on Canadian GAAP. US GAAP results would not differ significantly.

OUTLOOK

To achieve our mission and vision to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers, we will continue to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, employee engagement, shareholder value and productivity and cost-effectiveness. Given the nature of the work undertaken by our employees and contractors, safety remains our top priority. We will continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives.

We will continue to focus our efforts to improve our customers' satisfaction by meeting the unique needs of our diverse customer base through dialogue to understand their needs. We will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers more capability to manage their own costs. Most importantly, we are focused on becoming the customer's trusted advisor by providing access to specialized energy conservation teams to discuss the customer's opportunities to lower consumption, and through the use of a special team of agents to handle distributed generator inquiries and requirements.

Our assets are in the midst of a demographic change with an increasing proportion of assets reaching end-of-life and an increasing average asset age. Our focus is to address aging infrastructure, and to make needed asset replacement and maintenance investments, to maintain current and future system reliability for customers, within the policy set by the OEB. We will invest in technology that will provide us with real time asset condition and performance data giving us the visibility to make asset optimization life-cycle decisions, and opportunities through planning and scheduling data to improve materials procurement and to deploy work crews to better manage work programs to meet customer needs.

It is expected that the implementation of new asset management tools, such as Asset Analytics and Asset Investment Planning, will enhance risk-based investment planning, which considers such factors as asset condition, safety, performance, system function, customer impact, and statutory requirements allowing for targeted investment.

We will also continue to strive for productivity through efficiency and effective management of costs, which is key to achieving value for our customers and our shareholder.

Over the last four years, we have replaced most of our core information technology systems with an enterprise-wide IT system. We will leverage this investment as a platform for further effectiveness and efficiency gains, including enhancements in strategic sourcing. Further development of the existing IT platform will provide tools which are being developed to allow our company to effectively plan and reprioritize work and integrate customers' needs into multi-year investment plans. The outcomes are consistent with the OEB's direction in its new Outcomes-Based Approach to regulation.

We will be implementing the new CIS in 2013 that will improve customer service and corporate productivity by allowing the earlier investments in SAP to operate as an integrated platform. In addition, the first elements of the next generation of work delivery to be introduced through the Workflow of the Future Program in 2013 and 2014, and the use of information within the SAP systems, are expected to improve field-level productivity.

We are planning significant investments in transmission and distribution infrastructure and we will continue to focus on the operating and economic performance of our core utility operations in the provision of safe, cost-effective and reliable electricity delivery services to our customers, and in providing increasing enterprise value to the people of the province of Ontario. Productivity, value for money and improved employee and customer communications will be key areas of focus. We will continue to connect and support DG and investments made consistent with the LTEP.

Significant opportunity resides with smart meters and the proliferation of an ADS, including energy efficiency, demand response and distributed-resources technologies. We will invest in the development of an ADS and related grid modernization standards, customer demand work (connections and upgrades), smart meters, DG connections, including station upgrades, protection and control, new lines and some contestable work, for which the Company will receive capital contributions. There is little flexibility to reduce this work as most of it is customer demand driven.

As part of our new ADS, a new DMS will provide a monitoring and centralized control capability similar to that which already exists in the transmission system, and in selected areas of the distribution system. The new DMS was introduced in the Owen Sound pilot area and it will be expanded over time, as warranted. Future enhancements will also integrate the

Outage Response Management System with the Advanced Meter Infrastructure (i.e. smart meters) and with the DMS, to reduce System Average Interruption Duration Index and System Average Interruption Frequency Index.

The actual timing and expenditures in our business plan are predicated on obtaining various approvals including: OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities.

As stewards of significant electricity assets, we are committed to the protection and sustainment of the environment for future generations. We are working towards being an environmental leader in our industry, by distributing clean and renewable energy, by upgrading our electricity grid, by minimizing the impacts of our own operations, and by ensuring that environmental factors are considered in making our business decisions.

Key enablers of the successful implementation of our work programs are our human and material resourcing strategies. Our human resource strategy is focused on hiring through our apprenticeship program and our association with universities, colleges and our unions, as well as skills development and retention, including earlier identification and more rapid development of staff who demonstrate management potential. Effective use of human resources and ensuring correct skills will be critical to attaining the balance between meeting the asset needs and mitigating rate impact on the customer. Although our work program is assumed to grow moderately over the 2013 and 2014 years, no increase in regular staff numbers is anticipated over that period. With regard to materials, we are seeing a need for increasing lead times and costs as market shortages emerge globally. Consequently, materials sourcing strategies continue to be developed and implemented to ensure the availability of materials to support our work programs.

We remain committed to a prudent and measured approach to distribution rationalization. We have considered and will continue to consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects. The OEB notes in its *Framework for Transmission Project Development Plans* that where projects are otherwise equivalent or close in other factors, information such as socio-economic benefits, including First Nations involvement, could prove decisive in a competitive bid. As such, First Nations involvement in competitive bids is likely to become more prevalent.

APPOINTMENT OF CARMINE MARCELLO

On November 14, 2012, our Board of Directors appointed Carmine Marcello to the role of President and Chief Executive Officer, effective January 1, 2013. Mr. Marcello assumes his responsibilities following the planned retirement of outgoing President and Chief Executive Officer, Laura Formusa. Mr. Marcello has over 25 years' experience with our company as a senior executive, strategic planner and advisor on transmission and distribution utility processes in the electric utility industry.

APPOINTMENT OF YEZDI PAVRI

On December 6, 2012, Yezdi Pavri was appointed to our Board of Directors. Mr. Pavri is a Chartered Accountant and a former Vice-Chairman of Deloitte Canada. Mr. Pavri currently holds the position of Chair of the Board of Trustees of the United Way of Toronto.

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: statements about our strategy, including our strategic objectives; statements regarding our transmission and distribution rates; statements regarding load changes and associated impacts; statements regarding CDM programs and targets; the estimated impact of changes in the forecasted long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; statements related to economic conditions; expectations regarding energy-related revenues and profit and their trend; statements related to the GEA, the IPSP and the Ministry's LTEP and Supply Mix Directive, including additional investments arising therefrom and the timing and content of OPA recommendations; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility; expectations regarding our financing activities; statements regarding our maturing debt; 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; statements related to the OEB, including the renewed regulatory framework and revenue decoupling; 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 as well as our training and conversion plans; statements related to our agreement with the SON; statements related to our outlook including statements regarding our approach to distribution rationalization; and statements related to the FIT program. 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; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining 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 risks associated with the impending expiry of our collective agreements with both the Society and the PWU;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risks associated with the OEB's competitive transmission project development planning process;
- 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, and changes in benefits and actuarial assumptions;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with information system security, with maintaining a complex information technology system infrastructure, and with transitioning key enterprise IT systems;
- the risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that it may be determined that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems;
- 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 risks associated with the fact that some of our current and proposed transmission and distribution lines may traverse lands which First Nations and Métis have aboriginal, treaty or other legal claims;
- 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 this 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 February 14, 2013. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 14, 2013.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, internal and disclosure controls have been documented, evaluated, tested and identified consistent with National Instrument 52-109 (Bill 198). The effectiveness of these internal controls is evaluated and findings are reported to management and the Audit and Finance Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer and Executive Vice-President and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting pursuant to National Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Carmine Marcello

Carmine Marcello	Sandy Struthers
President and Chief Executive Officer	Chief Administration Officer and Chief Financial Officer

HYDRO ONE INC.
INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying consolidated financial statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011, the consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2012 and December 31, 2011, and its consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011 in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
February 14, 2013

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars, except per share amounts)	**2012**	**2011**
Revenues		*(Note 24)*
Distribution (includes $155 related party revenues; 2011 – $155) *(Note 19)*	4,184	4,019
Transmission (includes $1,482 related party revenues; 2011 – $1,372) *(Note 19)*	1,482	1,389
Other	62	63
	5,728	5,471
Costs		
Purchased power (includes $2,409 related party costs; 2011 – $2,427) *(Note 19)*	2,774	2,628
Operation, maintenance and administration *(Note 19)*	1,071	1,092
Depreciation and amortization *(Note 4)*	659	616
	4,504	4,336
Income before financing charges and provision for payments in lieu of corporate income taxes	1,224	1,135
Financing charges *(Note 5)*	358	344
Income before provision for payments in lieu of corporate income taxes	866	791
Provision for payments in lieu of corporate income taxes *(Notes 6, 19)*	121	150
Net income	745	641
Other comprehensive income	1	-
Comprehensive income	746	641
Basic and fully diluted earnings per common share *(dollars) (Note 17)*	7,280	6,228
Dividends per common share declared *(dollars) (Note 18)*	3,523	1,500

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (millions of dollars)	**2012**	**2011**
Assets		*(Note 24)*
Current assets:		
Short-term investments *(Note 12)*	195	228
Accounts receivable (net of allowance for doubtful accounts – $23; 2011 – $18) *(Note 7)*	845	805
Due from related parties *(Note 19)*	154	156
Regulatory assets *(Note 10)*	29	24
Materials and supplies	23	25
Deferred income tax assets *(Note 6)*	18	19
Derivative instruments *(Note 12)*	-	1
Other	22	19
	1,286	1,277
Property, plant and equipment *(Note 8)*:		
Property, plant and equipment in service	22,650	21,008
Less: accumulated depreciation	8,145	7,679
	14,505	13,329
Construction in progress	1,055	1,436
Future use land, components and spares	147	138
	15,707	14,903
Other long-term assets:		
Regulatory assets *(Note 10)*	3,098	1,966
Long-term investment *(Notes 11, 12, 19)*	251	250
Intangible assets (net of accumulated amortization – $305; 2011 – $257) *(Note 9)*	267	224
Goodwill	133	133
Deferred debt costs	34	32
Derivative instruments *(Note 12)*	19	33
Deferred income tax assets *(Note 6)*	14	17
Other	2	1
	3,818	2,656
Total assets	20,811	18,836

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

December 31 (millions of dollars, except number of shares)	**2012**	**2011**
Liabilities		*(Note 24)*
Current liabilities:		
Bank indebtedness *(Note 12)*	42	39
Accounts payable	140	154
Accrued liabilities *(Notes 6, 14, 15)*	582	575
Due to related parties *(Note 19)*	257	342
Accrued interest	95	85
Regulatory liabilities *(Note 10)*	40	25
Long-term debt payable within one year *(Notes 11, 12)*	600	600
	1,756	1,820
Long-term debt (includes $769 measured at fair value; 2011 – $783) *(Notes 11, 12)*	7,879	7,408
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	1,416	1,163
Deferred income tax liabilities *(Note 6)*	944	758
Pension benefit liability *(Note 14)*	1,515	779
Environmental liabilities *(Note 15)*	227	235
Regulatory liabilities *(Note 10)*	181	169
Net unamortized debt premiums	23	23
Asset retirement obligations *(Note 16)*	15	15
Long-term accounts payable and other liabilities	25	12
	4,346	3,154
Total liabilities	13,981	12,382
Contingencies and commitments (Notes 21, 22)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 17, 18)*	323	323
Shareholder's Equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 17, 18)*	3,314	3,314
Retained earnings	3,202	2,827
Accumulated other comprehensive loss	(9)	(10)
Total shareholder's equity	6,507	6,131
Total liabilities, preferred shares and shareholder's equity	20,811	18,836

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

James Arnett
Chair

Michael J. Mueller
Chair, Audit and Finance Committee

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

Year ended December 31, 2012 *(millions of dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholder's Equity
January 1, 2012	3,314	2,827	(10)	6,131
Net income	-	745	-	745
Other comprehensive income	-	-	1	1
Dividends on preferred shares	-	(18)	-	(18)
Dividends on common shares	-	(352)	-	(352)
December 31, 2012	3,314	3,202	(9)	6,507

Year ended December 31, 2011 *(millions of dollars)* *(Note 24)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholder's Equity
January 1, 2011	3,314	2,354	(10)	5,658
Net income	-	641	-	641
Other comprehensive income	-	-	-	-
Dividends on preferred shares	-	(18)	-	(18)
Dividends on common shares	-	(150)	-	(150)
December 31, 2011	3,314	2,827	(10)	6,131

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2012**	**2011**
Operating activities		*(Note 24)*
Net income	745	641
Environmental expenditures	(18)	(16)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	589	550
Regulatory assets and liabilities	12	47
Deferred income taxes	(9)	(12)
Asset retirement obligations	-	4
Other	6	9
Changes in non-cash balances related to operations *(Note 20)*	(40)	184
Net cash from operating activities	1,285	1,407
Financing activities		
Long-term debt issued	1,085	700
Long-term debt retired	(600)	(500)
Dividends paid	(370)	(168)
Change in bank indebtedness	3	39
Other	(1)	(4)
Net cash from (used in) financing activities	117	67
Investing activities		
Capital expenditures		
Property, plant and equipment	(1,363)	(1,371)
Intangible assets	(91)	(76)
Other	19	29
Net cash used in investing activities	(1,435)	(1,418)
Net change in cash and cash equivalents	(33)	56
Cash and cash equivalents, beginning of year	228	172
Cash and cash equivalents, end of year	195	228

See accompanying notes to 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).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These 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 Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. These statements are to be read in conjunction with Note 24 – Transition to US GAAP, which discloses information on the Canadian GAAP per Part V of the CICA Handbook (Canadian GAAP) to US GAAP transition and related reconciliations from Canadian GAAP to US GAAP. The results of operations for the year ended December 31, 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.

Hydro One performed an evaluation of subsequent events for the accompanying Consolidated Financial Statements and notes through to February 14, 2013, the date these Consolidated Financial Statements were issued, to determine whether the circumstances warranted recognition and disclosure of any events or transactions. No such events or transactions were identified.

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, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, 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 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 has approved US GAAP as the basis for rate setting for Hydro One Networks' Transmission and Distribution businesses and by Hydro One Remote Communities all effective January 1, 2012. Hydro One Brampton Networks' rates are currently set under Canadian GAAP, and are expected to be set under the OEB's modified International Financial Reporting Standards (IFRS) framework commencing in 2015, once its current Incentive Regulation Mechanism (IRM) period is complete.

Transmission

In May 2010, Hydro One Networks filed a cost-of-service application for 2011 and 2012 transmission rates in continued support of the Company's aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the Green Energy Act (GEA). This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012.

In December 2010, the OEB approved revenue requirements of $1,346 million for 2011 and $1,658 million for 2012. The approved 2012 revenue requirement was higher than that applied for, reflecting OEB direction to Hydro One to adopt a cost capitalization policy based on modified IFRS. This adjustment was subsequently reversed, when the OEB approved the use of US GAAP for transmission rate-setting purposes beginning January 1, 2012. Consequently, the OEB approved a revenue requirement of $1,418 million for 2012, along with new 2012 uniform transmission rates, with an effective date of January 1, 2012.

Distribution

In 2009, Hydro One Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $1,264 million. The application reflected the Company's plan to invest in its network assets to meet objectives regarding public and employee safety, regulatory and legislative compliance, maintenance of system security and reliability of system growth requirements, and to make investments required by the GEA. In April 2010, the OEB approved a revenue requirement of $1,236 million for 2011. The OEB also approved certain distribution regulatory account balances sought by Hydro One Networks in its application, including retail settlement variance accounts, retail cost variance accounts and smart meters. In November 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. A lowering of the return on equity produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year.

In 2010, Hydro One Brampton Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $63 million. In 2011, the OEB approved a revenue requirement of approximately $60 million for 2011, with an effective date of January 1, 2011. The reduced approved revenue requirement included a reduction to approved operation, maintenance and administration costs. In September 2011, Hydro One Brampton Networks filed an IRM application with the OEB for 2012 distribution rates, with an effective date of January 1, 2012. In January 2012, the OEB released a decision that resulted in a reduction in distribution rates of approximately 13.2% for 2012. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates.

In October 2010, Hydro One Remote Communities filed an IRM application with the OEB for 2011 rates. In March 2011, the OEB approved an increase of approximately 0.4% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2011. In November 2011, Hydro One Remote Communities filed an IRM application with the OEB for 2012 rates. In March 2012, the OEB approved an increase of approximately 1.1% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2012.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses 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 future 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.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments. Short-term investments have an original maturity of three months or less.

Revenue Recognition

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 electricity 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 electricity 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.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount or net realizable value, if unbilled. 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.

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% 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 judgement 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 their 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 tax asset to report the net 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 realized.

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

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only the ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

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

Property, Plant and Equipment

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

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

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 land access rights.

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), consulting, engineering, overheads and attributable capitalized 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.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing 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.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete 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, except for 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 OEB approval of 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	Rate (%)	
	Service Life	Range	Average
Transmission	56 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%.

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 such gain or loss 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 that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Per Accounting Standards Update (ASU) 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment, issued by the Financial Accounting Standards Board (FASB) in September 2011, the Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a 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.

For the year ended December 31, 2012, based on the qualitative assessment performed, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 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 most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is 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 December 31, 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 such amounts 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 within financing charges in the Consolidated Statements of Operations and Comprehensive Income. 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 amortization of net unamortized hedging losses on the Company's discounted cash flow hedges, and the change in fair value on the existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective-interest method over the term of the allocated hedged debt. Hydro One presents net income and OCI 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; 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 and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates 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 12 – Fair Value of Financial Instruments and Risk Management.

Short-term investments have an original maturity of three months or less and 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 December 31, 2012 and 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.

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 hedging relationships.

The accounting guidance for derivative instruments 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 on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments 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, net of tax, is reported as a component of accumulated OCI (AOCI) and is 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 derivative instruments 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 and had no embedded derivatives at December 31, 2012.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly 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 plans 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 plans 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. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

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

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 for financial reporting purposes. 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. 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 fair valued at the end of each year.

All future pension 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.

Post-retirement and post-employment benefits

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded on transition to US GAAP and at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates 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.

For post-retirement benefits, 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. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment 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), a multiemployer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on members' length of service and salary. Both participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated by member entity. OMERS is registered with the Financial Services Commission of Ontario under Registration #0345983.

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 obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton Networks' employees. Hydro One recognizes its contributions to the OMERS plan 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.

At December 31, 2011, OMERS had approximately 419,000 members, with approximately 277 members being current employees of Hydro One Brampton Networks.

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 judgements 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. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. 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 judgements 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 where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement 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 contaminated land assessment and remediation (LAR) 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. Where an asset is no longer in service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

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

Recently Adopted Accounting Pronouncements

In September 2011, the FASB issued ASU 2011-09, Disclosures About an Employer's Participation in a Multiemployer Benefit Plan. This ASU requires an employer to provide quantitative and qualitative disclosures 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. An employer that is not able to provide some of the quantitative information required by this ASU must disclose what information has been omitted and why it could not obtain the information. This ASU does not change the recognition and measurement guidance for an employer's participation in a multiemployer plan. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

In September 2011, the FASB issued ASU 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment. This ASU 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 adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income 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 shareholder's equity. The amendments in this ASU do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. Hydro One has elected to present OCI and net income in a single continuous Consolidated Statement of Operations and Comprehensive Income.

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. This 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. This ASU is largely consistent with existing US GAAP fair value measurement principles under Accounting Standards Codification 820. However, this 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. Required disclosures have been included in Note 12 – Fair Value of Financial Instruments and Risk Management. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset on the Consolidated Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement. The ASU was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity's 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 ASU only requires enhanced disclosures, the adoption of this ASU is not anticipated to have a significant impact on the Company's Consolidated Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of dollars)	**2012**	**2011**
Depreciation of property, plant and equipment	522	485
Amortization of intangible assets	48	45
Asset removal costs	70	66
Amortization of regulatory assets	19	20
	659	616

5. FINANCING CHARGES

Year ended December 31 (millions of dollars)	**2012**	**2011**
Interest on long-term debt	421	412
Other	12	5
Less: Interest capitalized on construction and development in progress	(59)	(58)
Gain on interest-rate swap agreements	(12)	(12)
Interest earned on investments	(4)	(3)
	358	344

6. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The major components of income tax expense are as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Current provision for PILs	130	162
Deferred recovery of PILs	(9)	(12)
Provision for PILs	121	150

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Income before provision for PILs	866	791
Canadian Federal and Ontario statutory income tax rate	26.50%	28.25%
Provision for PILs at statutory rate	230	223
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(42)	(34)
Pension contributions in excess of pension expense	(23)	(17)
Interest capitalized for accounting but deducted for tax purposes	(15)	(16)
Overheads capitalized for accounting but deducted for tax purposes	(14)	(12)
Non-refundable investment tax credits	(8)	-
Environmental expenditures	(5)	(4)
Post-retirement and post-employment benefit expense in excess of cash payments	-	5
Other	(3)	3
Net temporary differences	(110)	(75)
Net permanent differences	1	2
Total provision for PILs	121	150
Current provision for PILs	130	162
Deferred recovery of PILs	(9)	(12)
Total provision for PILs	121	150
Effective income tax rate	13.96%	18.96%

The current provision for PILs of $130 million represents the amount paid or payable to the OEFC with respect to current year income. The outstanding balance due to the OEFC at December 31, 2012 was $10 million (2011 – $85 million).

The total provision for PILs includes deferred recovery of PILs of $9 million that is 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.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	3	6
Post-retirement and post-employment benefits expense in excess of cash payments	7	5
Environmental expenditures	4	5
Other	-	1
Total deferred income tax assets	14	17
Less: current portion	-	-
	14	17

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,344)	(1,106)
Post-retirement and post-employment benefits expense in excess of cash payments	519	356
Environmental expenditures	62	61
Regulatory amounts receivable that are not recognized for tax purposes	(147)	(36)
Goodwill	(19)	(18)
Other	3	4
Total deferred income tax liabilities	(926)	(739)
Less: current portion	18	19
	(944)	(758)

During 2012, the deferred tax liability increased by $60 million as a result of the change in the rate applicable to future taxes. At December 31, 2012, unused tax losses carried forward were less than $1 million (2011 – less than $1 million).

7. ACCOUNTS RECEIVABLE

December 31 (millions of dollars)	**2012**	**2011**
Accounts receivable – billed	224	235
Accounts receivable – unbilled	644	588
Accounts receivable, gross	868	823
Allowance for doubtful accounts	(23)	(18)
Accounts receivable, net	845	805

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2012 and 2011.

Year ended December 31 (millions of dollars)	**2012**	**2011**
Allowance for doubtful accounts – January 1	(18)	(25)
Write-offs	17	30
Additions to allowance for doubtful accounts	(22)	(23)
Allowance for doubtful accounts – December 31	(23)	(18)

8. PROPERTY, PLANT AND EQUIPMENT

December 31 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
2012				
Transmission	11,840	3,990	641	8,491
Distribution	8,005	2,879	234	5,360
Communication	1,024	516	57	565
Administration and Service	1,314	668	123	769
Easements	614	92	-	522
	22,797	8,145	1,055	15,707
2011				
Transmission	10,906	3,810	1,079	8,175
Distribution	7,596	2,706	253	5,143
Communication	919	468	43	494
Administration and Service	1,232	607	61	686
Easements	493	88	-	405
	21,146	7,679	1,436	14,903

Financing charges capitalized on property, plant and equipment under construction were $56 million in 2012 (2011 – $57 million).

9. INTANGIBLE ASSETS

December 31 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2012				
Computer applications software	451	301	116	266
Other	5	4	-	1
	456	305	116	267
2011				
Computer applications software	427	254	49	222
Other	5	3	-	2
	432	257	49	224

Financing charges capitalized on intangible assets under development were $3 million in 2012 (2011 – $1 million). The estimated annual amortization expense for intangible assets for each of the next five years is $42 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (millions of dollars)	**2012**	**2011**
Regulatory assets:		
Pension benefit regulatory asset	1,515	779
Deferred income tax regulatory asset	954	763
Post-retirement and post-employment benefits	320	123
Environmental	249	257
Pension cost variance	61	42
Rider 2	10	11
Long-term project development costs	5	5
Other	13	10
Total regulatory assets	3,127	1,990
Less: current portion	29	24
	3,098	1,966
Regulatory liabilities:		
External revenue variance	61	39
Retail settlement variance accounts	54	39
Rider 8	45	41
Deferred income tax regulatory liability	16	25
PST savings deferral	13	8
Rider 3	9	9
Rural and remote rate protection variance	6	8
Hydro One Brampton Networks rider	-	2
Other	17	23
Total regulatory liabilities	221	194
Less: current portion	40	25
	181	169

Pension Benefit Regulatory Asset

The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $736 million (2011 – higher by $482 million).

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2012 provision for PILs would have been higher by approximately $136 million (2011 – $70 million), including the impact of a change in enacted tax rates.

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $197 million (2011 – higher by $30 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 15 – Environmental Liabilities). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2012, this regulatory asset decreased by $3 million (2011 – $55 million) to reflect related changes in the Company's PCB liability, and increased by $2 million (2011 – $5 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2012 operation, maintenance and administration expenses would have been lower by $1 million (2011 – $50 million). In addition, 2012 amortization expense would have been lower by $18 million (2011 – $16 million), and 2012 financing charges would have been higher by $11 million (2011 – $14 million).

Pension Cost Variance

A pension cost variance account was established for each of Hydro One Networks' Transmission and Distribution businesses to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension costs paid as compared to OEB-approved amounts. In December 2010, the OEB approved the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, 2012 revenue would have been lower by $18 million (2011 – $14 million).

Rider 2

In April 2006, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

Long-Term Project Development Costs

In May 2009, the OEB approved the creation of a deferral account to record Hydro One Networks' costs of preliminary work to advance certain transmission projects identified in the Company's 2009 and 2010 transmission rate applications. In March 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 2009 request from the Ministry of Energy and Infrastructure. In December 2010, the OEB approved the recovery of the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, 2011 operation, maintenance and administration expenses would have been lower by $2 million.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. These revenue sources are taken into account in structuring the Company's revenue requirement and as such, the OEB requested the establishment of new variance accounts to capture any difference between the approved forecasted external revenue amounts used in establishing the revenue requirement and actual external revenues. The external revenue variance account balance reflects the excess of actual external revenue compared to the OEB-approved forecasted amounts. In December 2010, the OEB approved the disposition of the December 31, 2009 balance, including accrued interest, to be disposed over a one-year period from January 1, 2011 to December 31, 2011.

Retail Settlement Variance Accounts (RSVAs)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In April 2010, the OEB approved the disposition of the total RSVA balance accumulated from May 2008 to December 2009, including accrued interest, to be disposed over a 20-month period from May 1, 2010 to December 31, 2011. Hydro One has continued to accumulate a net liability in its RSVA accounts since December 31, 2009.

Rider 8

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost of service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administrative expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable and calculations for tracking and refund were requested by the OEB. For the Hydro One Networks Transmission revenue requirement, PST was included between July 1, 2010 and December 31, 2010 and recorded in a deferral account per direction from the OEB. For the Hydro One Networks Distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2012 and recorded in a deferral account per direction from the OEB.

Rider 3

In December 2008, the OEB approved certain distribution-related deferral account balances sought by Hydro One, including RSVA amounts, deferred tax changes, OEB costs and smart meters. The OEB approved the disposition of the Rider 3 balance accumulated up to April 2008, including accrued interest, to be disposed over a 27-month period from February 1, 2009 to April 30, 2011.

Rural and Remote Rate Protection Variance (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. The OEB has approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked by the Company in the RRRP variance account.

Hydro One Brampton Networks Rider

In April 2010, the OEB issued a decision regarding the 2010 distribution rates of Hydro One Brampton Networks. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVAs, sought by Hydro One Brampton Networks in its application. The OEB ordered that the approved balances be aggregated into a single regulatory account and disposed of through a rate rider over a two-year period from May 1, 2010 to April 30, 2012.

11. DEBT AND CREDIT AGREEMENTS

Short-Term Notes

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program with a maximum amount of $1,000 million. These 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 December 31, 2012 and 2011.

The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving standby credit facility with a syndicate of banks and a long-term investment in Province of Ontario Floating-Rate Notes with a fair value of $251 million at December 31, 2012.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3,000 million. At December 31, 2012, $1,515 million remained available until September 2013.

The following table presents the outstanding long-term debt at December 31, 2012 and 2011:

December 31 (millions of dollars)	**2012**	**2011**
5.77% Series 3 notes due 2012	-	600
5.00% Series 15 notes due 2013	600	600
3.13% Series 19 notes due 2014[1]	750	750
2.95% Series 21 notes due 2015[1]	500	500
Floating-rate Series 22 notes due 2015[2]	50	50
4.64% Series 10 notes due 2016	450	450
Floating-rate Series 27 notes due 2016[2]	50	-
5.18% Series 13 notes due 2017	600	600
4.40% Series 20 notes due 2020	300	300
3.20% Series 25 notes due 2022	600	-
7.35% debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
5.00% Series 11 notes due 2046	325	325
4.00% Series 24 notes due 2051	225	100
3.79% Series 26 notes due 2062	310	-
	8,460	7,975
Add: Unrealized marked-to-market loss[1]	19	33
Less: Long-term debt payable within one year	(600)	(600)
Long-term debt	7,879	7,408

[1] The unrealized marked-to-market loss relates to $500 million of the Series 19 notes due 2014, and $250 million of the Series 21 notes due 2015. The unrealized marked-to-market loss is offset by a $19 million (2011 – $33 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 12 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[2] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

In 2012, Hydro One issued $1,085 million of long-term debt under the MTN Program, consisting of $300 million issued in the first quarter, $425 million issued in the second quarter, $310 million issued in the third quarter, and $50 million issued in the fourth quarter of 2012. In September 2012, the Company also redeemed the $600 million MTN Series 3 notes.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 12 – Fair Value of Financial Instruments and Risk Management.

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

12. 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 occur 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

At December 31, 2012 and 2011, the Company's carrying amounts of accounts receivable, due from related parties, short-term investments, bank indebtedness, accounts payable, accrued liabilities, and due to related parties 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 at December 31, 2012 and 2011 are as follows:

December 31 (millions of dollars)	2012 Carrying Value	2012 Fair Value	2011 Carrying Value	2011 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	512	512	521	521
$250 million of MTN Series 21 notes[2]	257	257	262	262
Other notes and debentures[3]	7,710	9,188	7,225	8,615
	8,479	9,957	8,008	9,398

[1] The fair value of $500 million of the MTN Series 19 notes 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 notes 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 notes and the MTN Series 21 notes 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 Derivative Instruments

At December 31, 2012, the Company had interest-rate swaps totaling $750 million (2011 – $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 was equal to about 9% (2011 – 9%) of its total long-term debt of $8,479 million (2011 – $8,008 million). At December 31, 2102, the Company had 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 notes 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 notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2012, the Company also had interest-rate swaps with a total notional value of $900 million classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(c) three $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 11, 2012 to December 11, 2013, from February 21, 2012 to February 19, 2013, and from February 19, 2013 to February 19, 2014, respectively;

(d) two $50 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 24, 2012 to January 24, 2013, and from January 24, 2013 to January 24, 2014; and

(e) 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 MTN Series 27 notes from March 4, 2013 to December 3, 2013.

At December 31, 2012 and 2011, the Company's carrying amounts of derivative instruments were representative of fair value.

Fair Value Hierarchy

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

December 31, 2012 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Short-term investments	195	195	-	195	-
Long-term investment	251	251	-	251	-
Derivative instruments					
Fair value hedges – interest-rate swaps	19	19	-	19	-
	465	465	-	465	-
Liabilities:					
Bank indebtedness	42	42	42	-	-
Long-term debt	8,479	9,957	-	9,957	-
	8,521	9,999	42	9,957	-

December 31, 2011 (millions of dollars)	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. The fair value of the short-term investments is determined using inputs other than quoted prices that are observable for the assets. The Company obtains quotes for the fair value of the short-term investments from an independent third party.

The long-term investment represents the Province of Ontario Floating-Rate Notes. The fair value of the long-term investment is determined using inputs other than quoted prices that are observable for the asset, with unrecognized gains or losses recognized in financing charges. The Company obtains quotes from an independent third party for the fair value of the long-term investment, who uses the market price of similar securities adjusted for changes in observable inputs such as maturity dates and interest rates.

The fair value of the derivative instruments is determined using other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2012 and 2011.

See Note 14 – Pension and Post-Retirement and Post-Employment Benefits 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 (2011 – $18 million) and Hydro One Networks' Distribution Business' results of operations by approximately $10 million (2011 – $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 derivative instruments 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 December 31, 2012 or 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 years ended December 31, 2012 or 2011.

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 years ended December 31, 2012 and 2011 are included in financing charges as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Unrealized loss (gain) on hedged debt	(14)	25
Unrealized loss (gain) on fair value interest-rate swaps	14	(25)
Net unrealized loss (gain)	-	-

At December 31, 2012, Hydro One had $750 million (2011 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $19 million (2011 – $33 million). During the years ended December 31, 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. At December 31, 2012 and 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. At December 31, 2012 and 2011, there was no significant accounts receivable balance due from any single customer.

At December 31, 2012, the Company's provision for bad debts was $23 million (2011 – $18 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2012, approximately 3% of the Company's accounts receivable were aged more than 60 days (2011 – 3%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; 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 December 31, 2012, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $22 million (2011 – $36 million). At December 31, 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.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, the revolving standby credit facility, and by holding Province of Ontario Floating-Rate Notes. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks maturing in June 2017 and the Province of Ontario Floating-Rate Notes with a fair value of $251 million. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2012, accounts payable and accrued liabilities in the amount of $722 million are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2012, Hydro One had issued long-term debt in the notional amount of $8,460 million (2011 – $7,975 million). Long-term debt maturing during the next year is $600 million (2011 – $600 million). Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $410 million (2011 – $408 million). Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table.

Years to Maturity	Principal Outstanding on Long-term Debt *(millions of dollars)*	Interest Payments[1] *(millions of dollars)*	Weighted Average Interest Rate[1] *(%)*
1 year	600	410	5.0
2 years	750	379	3.1
3 years	550	356	2.8
4 years	500	331	4.3
5 years	600	320	5.2
	3,000	1,796	4.1
6 – 10 years	900	1,403	3.6
Over 10 years	4,560	4,138	5.6
	8,460	7,337	4.9

[1] Interest payments and weighted average interest rates beyond 1 year exclude the impact of the $50 million floating-rate Series 22 notes due 2015 and the $50 million floating-rate Series 27 notes due 2016.

13. CAPITAL MANAGEMENT

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

The Company considers its capital structure to consist of shareholder's equity, preferred shares, long-term debt, and cash and cash equivalents. At December 31, 2012 and 2011, the Company's capital structure was as follows:

December 31 (millions of dollars)	**2012**	**2011**
Long-term debt payable within one year	600	600
Less: Cash and cash equivalents	195	228
	405	372
Long-term debt	7,879	7,408
Preferred shares	323	323
Common shares	3,314	3,314
Retained earnings	3,202	2,827
	6,516	6,141
Total capital	15,123	14,244

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2012 and 2011, Hydro One was in compliance with all of these covenants and limitations.

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (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 supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

The OMERS Plan

Hydro One contributions to the OMERS plan for the year ended December 31, 2012 were $2 million (2011 – $1 million). Company contributions payable at December 31, 2012 and included in accrued liabilities on the Consolidated Balance Sheets were $0.2 million (2011 – $0.2 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS plan, as indicated in OMERS's most recently available annual report for the year ended December 31, 2011.

At December 31, 2011, the OMERS plan was 88.7% funded, with an unfunded liability of $7,290 million. This unfunded liability will likely result in future payments by participating employers and members. Hydro One future contributions could be increased substantially if other entities withdraw from the plan.

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-represented staff 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. Annual Pension Plan contributions for 2012 of $163 million (2011 – $152 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2012 pensionable earnings. Estimated annual Pension Plan contributions for 2013 are $162 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment plans (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. For the year ended December 31, 2012, the measurement date for the Plans was December 31.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	5,461	4,996	1,206	1,178
Current service cost	123	108	29	30
Interest cost	285	286	63	68
Reciprocal transfers	1	4	-	-
Benefits paid	(291)	(289)	(42)	(42)
Net actuarial loss (gain)	928	356	203	(28)
Projected benefit obligation, end of year	6,507	5,461	1,459	1,206
Change in plan assets				
Fair value of plan assets, beginning of year	4,682	4,699	-	-
Actual return on plan assets	425	102	-	-
Reciprocal transfers	1	4	-	-
Benefits paid	(291)	(289)	-	-
Employer's contributions	163	153	-	-
Employees' contributions	27	27	-	-
Administrative expenses	(15)	(14)	-	-
Fair value of plan assets, end of year	4,992	4,682	-	-
Unfunded status	1,515	779	1,459	1,206

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

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Accrued liabilities	-	-	43	43
Pension benefit liability	1,515	779	-	-
Post-retirement and post-employment benefit liability	-	-	1,416	1,163
Unfunded status	1,515	779	1,459	1,206

The funded/unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for 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 (millions of dollars)	**2012**	**2011**
PBO	6,507	5,461
ABO	6,074	5,038
Fair value of plan assets	4,992	4,682

On an ABO basis, the plans were funded at 82% at December 31, 2012 (2011 – 93%). On a PBO basis, the plans were funded at 77% at December 31, 2012 (2011 – 86%). 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 table provides the components of the net periodic benefit costs for the years ended December 31, 2012 and 2011 for all plans:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Current service cost, net of employee contributions	96	81	30	30
Interest cost	285	286	63	67
Expected return on plan assets net of expenses	(289)	(291)	-	-
Actuarial loss amortization	112	68	8	7
Prior service cost amortization	3	4	3	4
Net Periodic Benefit Cost	207	148	104	108
Charged to results of operations[1]	76	93	48	61

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2012, pension costs of $163 million (2011 – $153 million) were attributed to labour, of which $76 million (2011 – $93 million) was charged to operations and $87 million (2011 – $60 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

Assumptions

The measurement of the obligations of the Plans and costs of providing benefits under Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed income securities.

The following weighted average assumptions were used to determine the benefit obligations and benefit expense at December 31, 2012 and 2011. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2012**	**2011**	**2012**	**2011**
Significant assumptions:				
For net periodic benefit cost, year ended December 31:				
Weighted average expected rate of return on plan assets	6.25%	6.25%	-	-
Weighted average discount rate	5.25%	5.75%	5.25%	5.75%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Average remaining service life of employees *(years)*	11	11	11	11
Rate of increase in health care cost trends[1]	-	-	4.41%	4.91%
For projected benefit obligation, at December 31:				
Weighted average discount rate	4.25%	5.25%	4.25%	5.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends[2]	-	-	4.39%	4.41%

[1] 7.03% per annum in 2012, grading down to 4.41% per annum in and after 2031 (2011 – 7.56% in 2011, grading down to 4.91% per annum in and after 2029)

[2] 6.91% per annum in 2013, grading down to 4.39% per annum in and after 2031 (2011 – 7.03% in 2012, grading down to 4.41% per annum in and after 2031)

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third party bond yield curve corresponding to each duration. The yield curve is based on AA long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of 1% change in health care cost trends on the post-retirement and post-employment benefits is as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Effect of 1% increase in health care cost trends on:		
Projected benefit obligation at December 31	246	174
Service cost and interest cost	17	20
Effect of 1% decrease in health care cost trends on:		
Projected benefit obligation at December 31	(191)	(138)
Service cost and interest cost	(13)	(14)

Estimated Future Benefit Payments

At December 31, 2012, estimated future benefit payments by the Company to Plan participants were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2013	299	51
2014	306	54
2015	313	57
2016	318	61
2017	324	64
2018 through to 2022	1,690	374
Total estimated future benefit payments through to 2022	3,250	661

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs 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 table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Actuarial loss (gain) for the year	807	558	203	(27)
Actuarial loss amortization	(112)	(68)	(8)	(7)
Prior service cost amortization	(3)	(4)	(3)	(3)
	692	486	192	(37)

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2012 and 2011:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Prior service cost	5	7	5	7
Actuarial loss	1,510	772	315	116
	1,515	779	320	123

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Prior service cost	2	3	3	3
Actuarial loss	175	112	17	4
	177	115	20	7

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

At December 31, 2012, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

December 31, 2012	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	64.1
Debt securities	35.0	35.8
Other [1]	5.0	0.1
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2012, the Pension Plan held $20 million of Hydro One corporate bonds (2011 – $27 million) and $243 million of debt securities of the Province (2011 – $214 million).

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, 2012 and 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, 2012 and 2011, there were no significant concentrations (defined as greater than 10% 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 derivative instruments by transacting only with financial institutions rated at least "AA" by S&P or "Aa2" 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 a recurring basis and their level within the fair value hierarchy at December 31, 2012 and 2011:

December 31, 2012 (millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	2	15	104	121
Cash and cash equivalents	125	-	-	125
Short-term securities	-	100	-	100
Real estate	-	-	2	2
Corporate shares – Canadian	920	-	-	920
Corporate shares – Foreign	2,077	-	-	2,077
Bonds and debentures – Canadian	-	1,643	-	1,643
Total fair value of plan assets[1]	3,124	1,758	106	4,988

[1] At December 31, 2012, the total fair value of Pension Plan assets excludes $16 million of interest and dividends receivable, $4 million relating to accruals for pending sales transactions and $8 million relating to accruals for pension administration expense.

December 31, 2011 (millions of dollars)	**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
Total fair value of plan assets[1]	2,771	1,729	167	4,667

[1] At December 31, 2011, the total fair value of Pension Plan assets excludes $17 million of interest and dividends receivable, $8 million of receivables relating to pending sales transactions, and $10 million relating to accruals for pension administration expense.

See Note 12 – Fair Value of Financial Instruments and Risk Management 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 years ended December 31, 2012 and 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.

Year ended December 31 (millions of dollars)	**2012**	**2011**
Fair value, beginning of year	167	167
Realized and unrealized gains	5	18
Purchases	6	9
Sales and disbursements	(72)	(27)
Fair value, end of year	106	167

There have been no material transfers into or out of Level 3 of the fair value hierarchy.

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 private equity investments. 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 includes 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 investments in the holding companies are valued using net asset values reported by the fund manager. Real estate investments are 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.

15. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Consolidated Balance Sheets at December 31, 2012 and 2011:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Environmental liabilities, January 1	199	58	257
Interest accretion	9	2	11
Expenditures	(8)	(10)	(18)
Revaluation adjustment	(3)	2	(1)
Environmental liabilities, December 31	197	52	249
Less: current portion	(13)	(9)	(22)
	184	43	227

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Environmental liabilities, January 1	251	58	309
Interest accretion	12	2	14
Expenditures	(9)	(7)	(16)
Revaluation adjustment	(55)	5	(50)
Environmental liabilities, December 31	199	58	257
Less: current portion	(13)	(9)	(22)
	186	49	235

The following table illustrates the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized in the Consolidated Balance Sheets after factoring in the discount rate:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Undiscounted environmental liabilities, December 31	233	54	287
Less: discounting accumulated liabilities to present value	(36)	(2)	(38)
Discounted environmental liabilities, December 31	197	52	249

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Undiscounted environmental liabilities, December 31	242	61	303
Less: discounting accumulated liabilities to present value	(43)	(3)	(46)
Discounted environmental liabilities, December 31	199	58	257

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2012 and in total thereafter are as follows: 2013 – $22 million; 2014 – $38 million; 2015 – $36 million; 2016 – $22 million; 2017 – $17 million; and thereafter – $152 million. At December 31, 2012, of the total estimated future environmental expenditures, $233 million relate to PCB (2011 – $242 million) and $54 million relate to LAR (2011 – $61 million).

Consistent with its accounting policy for environmental costs, Hydro One records a liability for the estimated mandatory future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment and for the assessment and remediation of chemically-contaminated lands.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting its expectation that future environmental costs will be recoverable in rates.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

PCBs

In September 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. These regulations impose timelines for disposal of PCBs based on certain criteria, including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except for specified equipment, had to be disposed of by the end of 2009, with the exception of specifically exempted equipment. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025.

Management judges that the Company currently has very few PCB-contaminated assets in excess of 500 ppm. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution and transmission station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is approximately $233 million. These expenditures are expected to be incurred over the period from 2013 to 2025. As a result of its most recent cost estimate to comply with current PCB regulations, the Company recorded a revaluation adjustment to reduce the PCB environmental liability by approximately $3 million (2011 – $55 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is approximately $54 million. These expenditures are expected to be incurred over the period from 2013 to 2020. As part of its annual review of environmental liabilities, the Company also reviewed its liability for LAR. As a result of this review, the Company recorded a revaluation adjustment to increase the LAR environmental liability by approximately $2 million (2011 – $5 million).

16. ASSET RETIREMENT OBLIGATIONS

AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO (with corresponding adjustments to property, plant and equipment), which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired and changes in federal, state or local regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

All factors used in estimating the Company's AROs represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. AROs are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for completing required removal and remediation work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3% to 5%, depending on the appropriate rate for the period when expenditures are expected to be incurred.

At December 31, 2012, Hydro One had recorded AROs of $15 million (2011 – $15 million), consisting of $7 million (2011 – $7 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $8 million (2011 – $8 million) related to the future decommissioning and removal of two of its switching stations.

The Company's liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities is based on management's best estimate of the present value of the estimated future expenditures to comply with current regulations. In 2010, the Company completed a study with the aid of an expert external consultant to estimate the future expenditures required to remove asbestos prior to facility demolition. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

In 2011, Hydro One recorded an ARO of $4 million related to the future decommissioning and removal of one of its switching stations, in addition to the ARO of $4 million recorded in a prior year related to the future decommissioning and removal of another switching station. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

17. SHARE CAPITAL

Preferred Shares

The Company has 12,920,000 issued and outstanding 5.5% cumulative preferred shares with a redemption value of $25 per share or $323 million total value. The Company is authorized to issue an unlimited number of 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 the redemption 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. Hydro One may elect, without condition, to pay all or part of the 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 at December 31, 2012. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

Common Shares

The Company has 100,000 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Common share dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial conditions, cash requirements, and other relevant factors, such as industry practice and shareholder expectations.

Earnings per Share

Earnings per share is calculated as net income for the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

18. DIVIDENDS

In 2012, preferred share dividends in the amount of $18 million (2011 – $18 million) and common share dividends in the amount of $352 million (2011 – $150 million) were declared.

19. 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. 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 revenues include $1,474 million (2011 – $1,366 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues include $127 million (2011 – $127 million) related to this program. In 2012, Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenues include $28 million (2011 – $28 million) related to these services.

In 2012, Hydro One purchased power in the amount of $2,392 million (2011 – $2,401 million) from the IESO-administered electricity market; $10 million (2011 – $16 million) from OPG; and $7 million (2011 – $10 million) 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 transmitters. In 2012, Hydro One incurred $11 million (2011 – $11 million) in OEB fees.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2012, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $10 million (2011 – $7 million), primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were $2 million in 2012 (2011 – $2 million).

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 2012, Hydro One received $39 million (2011 – $39 million) from the OPA related to the 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. At December 31, 2012, the Company held Province of Ontario Floating-Rate Notes with a fair value of $251 million (2011 – $250 million).

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

December 31 (millions of dollars)	**2012**	**2011**
Due from related parties	154	156
Due to related parties[1]	(257)	(342)
Long-term investment	251	250

[1] Included in due to related parties at December 31, 2012 are amounts owing to the IESO in respect of power purchases of $199 million (2011 – $209 million).

20. CONSOLIDATED STATEMENTS OF CASH FLOWS

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

Year ended December 31 (millions of dollars)	**2012**	**2011**
Accounts receivable	(30)	(18)
Due from related parties	2	(32)
Materials and supplies	2	(4)
Other assets	(4)	(11)
Accounts payable	(14)	29
Accrued liabilities	10	98
Due to related parties	(85)	61
Accrued interest	10	1
Long-term accounts payable and other liabilities	13	-
Post-retirement and post-employment benefit liability	56	60
	(40)	184

Supplementary information:		
Net interest paid	411	410
Payments in lieu of corporate income taxes	197	80

21. 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 the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company 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 in 2012. If the Company cannot obtain the required consents, 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 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 the Company is not able to recover them in future rate orders.

22. 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.

At December 31, 2012, the annual commitments under the Inergi agreement are as follows: 2013 – $136 million; 2014 – $130 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 December 31, 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 (2011 – $325 million), and on behalf of two distributors using guarantees of $0.7 million (2011 – $0.7 million). 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 $22 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 letters of credit plus the nominal amount of the parental guarantees.

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 supplementary pension plan trustee is required to draw upon these 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 letters of credit. At December 31, 2012, Hydro One had letters of credit of $127 million (2011 – $124 million) outstanding relating to retirement compensation arrangements.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service related functions and storing telecommunication equipment. These leases have an average life of between one and five years with renewal options for periods ranging from one to 10 years included in some of the contracts. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions. There are no restrictions placed upon Hydro One by entering into these leases. Hydro One Networks and Hydro One Telecom are the principal entities concerned.

At December 31, 2012, the future minimum lease payments under non-cancellable operating leases were as follows:

December 31 (millions of dollars)	**2012**	**2011**
Within one year	10	8
After one year but not more than five years	29	26
More than five years	14	20
	53	54

During the year ended December 31, 2012, the Company made lease payments totaling $9 million (2011 – $6 million).

23. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing electricity 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. Operating segments for the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance at each of the segments. The Company evaluates segment performance based on income before financing charges and provision for PILs from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Year ended December 31, 2012 (millions of dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment profit				
Revenues	1,482	4,184	62	5,728
Purchased power	-	2,774	-	2,774
Operation, maintenance and administration	402	608	61	1,071
Depreciation and amortization	320	329	10	659
Income (loss) before financing charges and provision for PILs	760	473	(9)	1,224
Financing charges				358
Income before provision for PILs				866
Capital expenditures	776	671	7	1,454

Year ended December 31, 2011 (millions of dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment profit				
Revenues	1,389	4,019	63	5,471
Purchased power	-	2,628	-	2,628
Operation, maintenance and administration	422	609	61	1,092
Depreciation and amortization	302	304	10	616
Income (loss) before financing charges and provision for PILs	665	478	(8)	1,135
Financing charges				344
Income before provision for PILs				791
Capital expenditures	810	628	9	1,447

December 31 (millions of dollars)	**2012**	**2011**
Total assets		
Transmission	11,586	10,589
Distribution	8,621	7,594
Other	604	653
	20,811	18,836

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

24. 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. The Company's transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to the Company's 2012 Consolidated Financial Statements.

Measurement and classification differences resulting from Hydro One'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 resulting from Hydro One'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:

(millions of dollars)	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:

(millions of dollars)	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 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Cash		33	-	33
Short-term investments		139	-	139
Accounts receivable	F	911	(124)	787
Due from related parties	F	-	124	124
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 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	D, F	884	(884)	-
Accounts payable	D	-	125	125
Accrued liabilities	D	-	478	478
Due to related parties	F	-	281	281
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	E	-	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	-
Common shares		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 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Short-term investments		228	-	228
Accounts receivable	F	961	(156)	805
Due from related parties	F	-	156	156
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 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Bank indebtedness		39	-	39
Accounts payable and accrued charges	D, F	1,071	(1,071)	-
Accounts payable	D	-	154	154
Accrued liabilities	D	-	575	575
Due to related parties	F	-	342	342
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	E	-	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	-
Common shares		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 (millions of dollars)	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 reclassified outside shareholder's equity	-	(323)	-	-	(323)
US GAAP	3,314	-	(10)	2,354	5,658

December 31, 2011 *(millions of dollars)*	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 reclassified 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".

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

(millions of dollars)	**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 benefit obligations on the Consolidated Balance Sheets. Under US GAAP, the Company recognized the unfunded status of pension, post-retirement and post-employment benefit 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 benefit 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.

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

(millions of dollars)	**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 offsetting regulatory assets for incremental obligations 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. Derivative Instruments (classification change)

Under Canadian GAAP, the Company classified its derivative instruments 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”.

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

(millions of dollars)	**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”.

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

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Current liabilities:		
Accounts payable	125	154
Accrued liabilities	478	575
Accounts payable and accrued charges	(603)	(729)

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 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 accrued as declared (see Note 17 – Share Capital).

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

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Preferred shares	323	323
Shareholder's equity:		
Preferred shares	(323)	(323)

F. Related Party Balances (classification change)

Under Canadian GAAP, receivables from related parties and payables to related parties were disclosed as "Accounts receivable" and "Accounts payable and accrued charges", respectively. Under US GAAP, receivables from related parties are recognized in "Due from related parties" and payables to related parties are recognized in "Due to related parties".

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

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Current assets:		
Due from related parties	124	156
Accounts receivable	(124)	(156)
Current liabilities:		
Due to related parties	281	342
Accounts payable and accrued charges	(281)	(342)

25. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2012 Consolidated Financial Statements.

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Statements of Operations Data *Year ended December 31 (millions of dollars)*	**2012**[1]	**2011**[1]	**2010**[2]	**2009**[2]	**2008**[2]
Revenues					
Distribution	4,184	4,019	3,754	3,534	3,334
Transmission	1,482	1,389	1,307	1,147	1,212
Other	62	63	63	63	51
	5,728	5,471	5,124	4,744	4,597
Costs					
Purchased power	2,774	2,628	2,474	2,326	2,181
Operation, maintenance and administration	1,071	1,092	1,078	1,057	965
Depreciation and amortization	659	616	583	537	548
	4,504	4,336	4,135	3,920	3,694
Income before financing charges and provision for payments in lieu of corporate income taxes	1,224	1,135	989	824	903
Financing charges	358	344	342	308	292
Income before provision for payments in lieu of corporate income taxes	866	791	647	516	611
Provision for payments in lieu of corporate income taxes	121	150	56	46	113
Net income	745	641	591	470	498
Basic and fully diluted earnings per common share *(dollars)*	7,280	6,228	5,727	4,528	4,797
Dividends per common share declared *(dollars)*	3,523	1,500	100	1,700	2,410

Balance Sheets Data *December 31 (millions of dollars)*	**2012**[1]	**2011**[1]	**2010**[1]	**2009**[2]	**2008**[2]
Assets					
Distribution	8,621	7,594	6,915	6,481	5,873
Transmission	11,586	10,589	9,820	8,993	7,877
Other	604	653	609	161	128
Total Assets	20,811	18,836	17,344	15,635	13,878
Liabilities					
Current liabilities (including current portion of long-term debt)	1,756	1,820	1,540	1,655	1,300
Long-term debt	7,879	7,408	7,283	6,281	5,733
Other long-term liabilities	4,346	3,154	2,540	2,281	1,721
Preferred shares	323	323	323	-	-
Shareholder's equity					
Preferred shares	-	-	-	323	323
Common shares	3,314	3,314	3,314	3,314	3,314
Retained earnings	3,202	2,827	2,354	1,791	1,497
Accumulated other comprehensive income	(9)	(10)	(10)	(10)	(10)
Total liabilities, preferred shares and shareholder's equity	20,811	18,836	17,344	15,635	13,878

[1] Based on US GAAP

[2] Based on Canadian GAAP

Other Financial Data *Year ended December 31*	**2012**	**2011**	**2010**	**2009**	**2008**
Capital expenditures *(millions of dollars)*					
Distribution	671	628	629	643	570
Transmission	776	810	936	918	704
Other	7	9	5	5	10
Total capital expenditures	1,454	1,447	1,570	1,566	1,284
Ratios					
Net asset coverage on long-term debt ratio[1]	1.81	1.81	1.77	1.79	1.84
Earnings coverage ratio[2]	2.83	2.71	2.39	2.15	2.63
Operating statistics					
Transmission					
Units transmitted *(TWh)*[3]	141.3	141.5	142.2	139.2	148.7
Ontario 20-minute system peak demand *(MW)*[3]	24,768	25,505	25,145	24,477	24,231
Ontario 60-minute system peak demand *(MW)*[3]	24,636	25,450	25,075	24,380	24,195
Total transmission lines *(circuit-kilometres)*	29,327	28,942	28,951	28,924	29,039
Distribution					
Units distributed to Hydro One customers *(TWh)*[3]	29.2	29.2	29.1	28.9	29.9
Units distributed through Hydro One lines *(TWh)*[3,4]	42.4	42.5	42.5	43.5	44.7
Total distribution lines *(circuit-kilometres)*	121,525	120,514	123,552	123,528	123,260
Customers	1,381,926	1,365,379	1,345,177	1,333,920	1,325,745
Total regular employees	5,811	5,781	5,717	5,427	5,032

[1] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[2] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[3] System-related statistics include preliminary figures for December.

[4] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2013

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying financial statements of the Distribution Business (a business of Hydro One Networks Inc.), which comprise the balance sheet as at December 31 2013, the statements of operations and comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The financial statements have been prepared by management in accordance with the basis of accounting in Note 2 of these financial statements.

Management's Responsibility for the Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these financial statements in accordance with the basis of accounting in Note 2 to these financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Distribution Business (a business of Hydro One Networks Inc.) as at December 31, 2013, and its statement of operations and comprehensive income, and its cash flows for the year then ended, in accordance with the basis of accounting as set out in Note 2 to these financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to these financial statements, which describes the basis of accounting and composition of the Distribution Business (a business of Hydro One Networks Inc.). In particular, in preparing these financial statements, long-term debt, shared functions and service costs, and payments in lieu of corporate income taxes have been allocated to the Distribution Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to these financial statements. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position, results of operations and cash flows that would have resulted had the Distribution Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. These financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, these financial statements may not be suitable for another purpose. Our report is intended solely for Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 26, 2014

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Revenues		
Energy sales	3,806	3,536
Rural rate protection *(Note 18)*	125	125
Other	40	53
	3,971	3,714
Costs		
Purchased power *(Note 18)*	2,620	2,413
Operation, maintenance and administration *(Note 18)*	611	553
Depreciation and amortization *(Note 4)*	321	308
	3,552	3,274
Income before financing charges and provision for payments in lieu of corporate income taxes	419	440
Financing charges *(Notes 5, 18)*	137	138
Income before provision for payments in lieu of corporate income taxes	282	302
Provision for payments in lieu of corporate income taxes *(Notes 6, 18)*	24	44
Net income	258	258
Other comprehensive income	–	–
Comprehensive income	258	258

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS
At December 31, 2013 and 2012

December 31 (millions of Canadian dollars)	**2013**	**2012**
Assets		
Current assets:		
Inter-company demand facility *(Notes 12, 13, 18)*	47	5
Accounts receivable (net of allowance for doubtful accounts – $32; 2012 – $20) *(Notes 7,18)*	853	778
Regulatory assets *(Note 10)*	15	14
Materials and supplies	6	7
Deferred income tax assets *(Note 6)*	8	7
Derivative instruments *(Note 12)*	1	–
Other	11	12
	941	823
Property, plant and equipment *(Note 8)*:		
Property, plant and equipment in service	8,864	8,363
Less: accumulated depreciation	3,279	3,078
	5,585	5,285
Construction in progress	323	314
Future use land, components and spares	45	45
	5,953	5,644
Other long-term assets:		
Regulatory assets *(Note 10)*	705	612
Intangible assets (net of accumulated amortization – $145; 2012 – $178) *(Note 9)*	204	159
Goodwill	73	73
Deferred debt costs	13	12
Derivative instruments *(Note 12)*	2	5
	997	861
Total assets	7,891	7,328

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)
At December 31, 2013 and 2012

December 31 (millions of Canadian dollars)	**2013**	**2012**
Liabilities		
Current liabilities:		
Accounts payable	59	58
Accrued liabilities *(Notes 6, 14, 15, 18)*	592	592
Accrued interest *(Note 18)*	38	35
Regulatory liabilities *(Note 10)*	26	38
Long-term debt payable within one year *(Notes 11, 12, 13, 18)*	176	230
	891	953
Long-term debt *(Notes 11, 12, 13, 18)*	3,140	2,785
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	824	785
Deferred income tax liabilities *(Note 6)*	306	230
Environmental liabilities *(Note 15)*	139	132
Regulatory liabilities *(Note 10)*	110	96
Net unamortized debt premiums	11	12
Asset retirement obligations *(Note 16)*	4	3
Long-term accounts payable and other liabilities	1	13
	1,395	1,271
Total liabilities	5,426	5,009
Contingencies and commitments (Notes 20, 21)		
Excess of assets over liabilities *(Notes 13, 17)*	2,465	2,319
Total liabilities and excess of assets over liabilities	7,891	7,328

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Carmine Marcello
Chair

Sandy Struthers
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Operating activities		
Net income	258	258
Environmental expenditures	(9)	(9)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	270	262
Regulatory assets and liabilities	(12)	(5)
Deferred income taxes	3	2
Other	2	1
Changes in non-cash balances related to operations *(Note 19)*	(30)	(45)
Net cash from operating activities	482	464
Financing activities		
Long-term debt issued	533	454
Long-term debt retired	(230)	(324)
Payments to Hydro One Inc. to finance dividends	(112)	(107)
Other	(2)	–
Net cash from financing activities	189	23
Investing activities		
Capital expenditures *(Note 19)*		
Property, plant and equipment	(579)	(562)
Intangible assets	(66)	(73)
Other	16	12
Net cash used in investing activities	(629)	(623)
Net change in inter-company demand facility	42	(136)
Inter-company demand facility, beginning of year	5	141
Inter-company demand facility, end of year	47	5

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) 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.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP). These Financial Statements have been prepared for the specific use of the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2013 have been prepared and are publicly available.

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Distribution Business on a basis approved by the OEB. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company's Distribution Business. As a result of this basis of accounting, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Payments in lieu of corporate income taxes (PILs) have been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Distribution Business was a separate taxpaying entity. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB. Certain comparative figures have been reclassified to conform to the presentation of these Financial Statements (see Note 19 – Statements of Cash Flows).

Hydro One Networks performed an evaluation of subsequent events through to March 26, 2014, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these financial statements. See Note 22 – Subsequent Events.

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, expenses, gains and losses 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 assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, 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 OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by the Company's Distribution Business beginning with the year 2012.

In 2010, the OEB approved a revised 2011 revenue requirement of $1,218 million and 2011 distribution rates. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year. In June 2012, Hydro One Networks filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2013 distribution rates. In December 2012, the OEB approved an increase in average distribution rates of approximately 1.3%, with an effective date of January 1, 2013.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses 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 Distribution Business' 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 Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Distribution Business 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 Distribution Business 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

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 electricity 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 are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are estimated and recorded based on wholesale electricity purchases. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Distribution Business' best estimate of losses on billed accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Distribution Business 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 110 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.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One Networks is required to remit 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% 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 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 Financial Statements and their 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 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 realized.

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

The Distribution Business uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

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

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, 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 Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized 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 costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of 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.

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 amounts incurred to acquire land rights and other access rights.

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), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Distribution Business' intangible assets primarily represent major administrative computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing 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 Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete 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, except for transport and work equipment, which is depreciated on a declining balance basis.

Hydro One 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 OEB approval of 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, 2013. 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
Distribution	40 years	1% – 20%	2%
Communication	10 years	2% – 9%	9%
Administration and service	17 years	3% – 9%	7%

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

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 and amortization, 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 such gain or loss 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 that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a 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.

For the year ended December 31, 2013, based on the qualitative assessment performed as at September 30, 2013, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2013.

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.

The carrying costs of most of the Distribution Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2013, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the 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 within financing charges in the Statements of Operations and Comprehensive Income. 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 amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges, and the change in fair value on the Company's proportionate share of existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its share of unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the allocated hedged debt. OCI and net income are presented in a single continuous 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. Hydro One Networks 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 its risk management policy disclosed in Note 12 – Fair Value of Financial Instruments and Risk Management.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various derivative 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. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments 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 on the Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized in its 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, net of tax, is reported as a component of accumulated OCI (AOCI) and is 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 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 Statements of Operations and Comprehensive Income. Additionally, Hydro One 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 derivative instruments are separated from their host contracts and carried at fair value on the 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. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2013.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where Hydro One has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly 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 pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One 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 on the Consolidated Balance Sheets of Hydro One 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 post-retirement and post-employment benefit plans are unfunded because there are no related plan assets. For the year ended December 31, 2013, the measurement date for the Plans was December 31.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the pension plan allocated to, or funded separately by, entities within the consolidated group. Consequently, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

A detailed description of Hydro One pension benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2013.

Post-retirement and post-employment benefits

Post-retirement and post-employment benefits are recorded and included in rates 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.

The Company records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for 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 post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

For post-retirement benefits, 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. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment 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.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2013.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Distribution Business' 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. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Distribution Business 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 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 Distribution Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each 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 could also change the estimated liability. 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. The Distribution Business records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 present value is determined 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 it is anticipated 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. The estimates of future environmental expenditures are reviewed 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. Where an asset is no longer in-service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some 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 Distribution Business 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 case, an ARO would be recorded at that time.

The Distribution Business' 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

Recently Adopted Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset on the Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement. The ASU was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity's financial position. This ASU was required to be applied retrospectively and was effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. The adoption of this ASU did not have a significant impact on the Distribution Business' Financial Statements.

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This ASU requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount reclassified is required under US GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under US GAAP that provide additional detail about those amounts. This ASU was required to be applied prospectively and was effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. The adoption of this ASU did not have a significant impact on the Distribution Business' Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU provides guidance on the presentation of unrecognized tax benefits. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, and should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The adoption of this ASU is not anticipated to have a significant impact on the Distribution Business' Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Depreciation of property, plant and equipment	235	229
Amortization of intangible assets	26	24
Asset removal costs	51	46
Amortization of regulatory assets	9	9
	321	308

5. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Interest on long-term debt	150	154
Other	5	8
Interest on inter-company demand facility	1	–
Less: Interest capitalized on construction and development in progress	(16)	(18)
Gain on interest-rate swap agreements	(3)	(4)
Interest earned on inter-company demand facility	–	(2)
	137	138

6. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Income before provision for PILs	282	302
Canadian Federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	75	80
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(28)	(8)
Pension contributions in excess of pension expense	(10)	(12)
Overheads capitalized for accounting but deducted for tax purposes	(6)	(6)
Prior year’s adjustment	(5)	–
Interest capitalized for accounting but deducted for tax purposes	(4)	(4)
Environmental expenditures	(2)	(2)
Non-refundable ITCs	(2)	(6)
Post-retirement and post-employment benefit expense in excess of cash payments	3	–
Other	2	1
Net temporary differences	(52)	(37)
Net permanent differences	1	1
Total provision for PILs	24	44
Current provision for PILs	21	42
Deferred provision for PILs	3	2
Total provision for PILs	24	44
Effective income tax rate	8.51%	14.57%

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2013, $19 million receivable from the OEFC was included in accounts receivable on the Balance Sheet (December 31, 2012 – payable of $7 million included in accrued liabilities).

The total provision for PILs includes deferred provision for PILs of $3 million (2012 – $2 million) that is 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.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(547)	(458)
Regulatory amounts not recognized for tax	(87)	(84)
Goodwill	(8)	(8)
Post-retirement and post-employment benefits expense in excess of cash payments	304	290
Environmental expenses	39	36
Other	1	1
Total deferred income tax liabilities	(298)	(223)
Less: current portion	8	7
	(306)	(230)

During 2013, there was no change in the rate applicable to future taxes (2012 – a change in rate applicable to future rates generated a $14 million increase).

7. ACCOUNTS RECEIVABLE

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Accounts receivable – billed	238	200
Accounts receivable – unbilled	647	598
Accounts receivable, gross	885	798
Allowance for doubtful accounts	(32)	(20)
Accounts receivable, net	853	778

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2013 and 2012.

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Allowance for doubtful accounts – January 1	(20)	(15)
Write-offs	23	16
Additions to allowance for doubtful accounts	(35)	(21)
Allowance for doubtful accounts – December 31	(32)	(20)

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2013 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Distribution	7,939	2,763	307	5,483
Communication	106	29	–	77
Administration and Service	855	483	16	388
Easements	9	4	–	5
	8,909	3,279	323	5,953

December 31, 2012 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Distribution	7,476	2,602	220	5,094
Communication	100	21	–	79
Administration and Service	824	451	94	467
Easements	8	4	–	4
	8,408	3,078	314	5,644

Financing charges capitalized on property, plant and equipment under construction were $13 million (2012 – $15 million).

9. INTANGIBLE ASSETS

December 31, 2013 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	347	144	1	204
Other	1	1	–	–
	348	145	1	204

December 31, 2012 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	228	176	107	159
Other	2	2	–	–
	230	178	107	159

Financing charges capitalized on intangible assets under development were $3 million (2012 – $3 million). The estimated annual amortization expense for intangible assets is as follows: 2014 – $31 million; 2015 – $31 million; 2016 – $31 million; 2017 – $31 million; and 2018 – $28 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Regulatory assets:		
Deferred income tax regulatory asset	310	239
Post-retirement and post-employment benefits	172	180
Environmental	152	140
Pension cost variance	59	46
OEB cost assessment differential	9	–
DSC exemption	7	–
Rider 2	–	10
Other	11	11
Total regulatory assets	720	626
Less: current portion	15	14
	705	612

December 31 (millions of Canadian dollars)	**2013**	**2012**
Regulatory liabilities:		
Rider 8	54	45
Retail settlement variance accounts	35	46
Rider 9	19	–
PST savings deferral	14	10
Deferred income tax regulatory liability	7	7
Rider 3	–	9
Rural and remote rate protection variance	–	6
Other	7	11
Total regulatory liabilities	136	134
Less: current portion	26	38
	110	96

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Distribution Business has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Distribution Business' provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be reflected in future rates. As a result, the 2013 provision for PILs would have been higher by approximately $53 million (2012 – $41 million).

Post-Retirement and Post-Employment Benefits

The Distribution Business recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2013 OCI would have been higher by $8 million (2012 – lower by $110 million).

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, an equivalent amount was recorded as a regulatory asset. In 2013, the environmental regulatory asset decreased by $3 million (2012 – $2 million) to reflect related changes in the PCB liability, and increased by $18 million (2012 – $2 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2013 operation, maintenance and administration expenses would have been higher by 15 million (2012 – no change). In addition, 2013 amortization expense would have been lower by $9 million (2012 – $9 million), and 2013 financing charges would have been higher by $6 million (2012 – $6 million).

Pension Cost Variance

A pension cost variance account was established for the Distribution Business to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In the absence of rate-regulated accounting, 2013 revenue would have been lower by $13 million (2012 – $17 million).

OEB Cost Assessment Differential

In April 2010, the OEB announced its decision regarding the Distribution Business' rate application for 2010 and 2011. As part of this decision, the OEB also approved the distribution-related OEB Cost Assessment Differential Account to record the difference between the amounts approved in rates and actual expenditures with respect to the OEB's cost assessments.

DSC Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the Distribution System Code (DSC), with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by the Company that resulted from the connection of certain renewable generation facilities. The OEB ruled that expenditures for identified specific expenditures can be recorded in a deferral account, subject to the OEB's review at a future date.

Rider 2

In April 2006, the OEB approved Hydro One Networks' distribution-related deferral account balances. The Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved the balance of the Rider 2 regulatory account for disposition as part of Rider 9, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

Rider 8

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

Retail Settlement Variance Accounts (RSVA)

The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In December 2012, the OEB approved the disposition of the total RSVA balance accumulated from January 2010 to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014. The Company has continued to accumulate a net liability in its RSVAs since December 31, 2011.

Rider 9

In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved for disposition certain distribution-related deferral account balances, including RSVA amounts and balances of Rider 2 and Rider 3, accumulated up to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost of service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administrative expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable and calculations for tracking and refund were requested by the OEB. For the Distribution Business, PST was included in rates between July 1, 2010 and December 31, 2013 and recorded in a deferral account per direction from the OEB.

Rider 3

In December 2008, the OEB approved certain distribution-related deferral account balances sought by the Company, including RSVA amounts, deferred tax changes, OEB costs and smart meters. The OEB approved the disposition of the Rider 3 balance accumulated up to April 2008, including accrued interest, to be disposed over a 27-month period from February 1, 2009 to April 30, 2011. In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved the balance of Rider 3 for disposition as part of Rider 9.

Rural and Remote Rate Protection Variance (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. The OEB has approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One Networks and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked in the RRRP variance account. At December 31, 2013, the RRRP variance account had a $2 million debit balance, which is included in Other regulatory assets.

11. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, which is then allocated between the Company's transmission and distribution businesses.

The following table presents the outstanding long-term debt of the Distribution Business as at December 31, 2013 and 2012:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Long-term debt	3,313	3,010
Add: Unrealized marked-to-market loss[1]	3	5
Less: Long-term debt payable within one year	(176)	(230)
Long-term debt	3,140	2,785

[1] The unrealized marked-to-market loss relates to $100 million of Distribution Business' $175 million note due 2014, and $100 million of Distribution Business' $200 million note due 2015. The unrealized marked-to-market loss is offset by a $3 million (2012 – $5 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 12 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 12 – Fair Value of Financial Instruments and Risk Management.

12. 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.

The Company 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

At December 31, 2013 and 2012, the carrying amounts of accounts receivable, inter-company demand facility, and accounts payable 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 Distribution Business' long-term debt at December 31, 2013 and 2012 are as follows:

December 31 (millions of Canadian dollars)	2013 Carrying Value	2013 Fair Value	2012 Carrying Value	2012 Fair Value
Long-term debt				
$100 million of $175 million notes due 2014[1]	101	101	102	102
$100 million of $200 million notes due 2015[2]	102	102	103	103
Other notes and debentures[3]	3,113	3,370	2,810	3,338
	3,316	3,573	3,015	3,543

[1] The fair value of $100 million of Distribution Business' $175 million notes due 2014, 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 $100 million of Distribution Business' $200 million notes due 2015, 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 Distribution Business' $175 million and $200 million notes 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 Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

At December 31, 2013, the Distribution Business' share of the Company's derivative instruments include $200 million of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt (2012 – $200 million). These interest-rate swaps are classified as fair value hedges. The Distribution Business' fair value hedge exposure was equal to about 6% (2012 – 7%) of its long-term debt. At December 31, 2013, the Distribution Business' interest-rate swaps designated as fair value hedges were as follows:

(a) a $100 million fixed-to-floating interest-rate swap agreement to convert $100 million of the $175 million notes maturing November 19, 2014 into three-month variable rate debt; and

(b) two $50 million fixed-to-floating interest-rate swap agreements to convert $100 million of the $200 million notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2013, the Distribution Business' share of interest-rate swaps classified as undesignated contracts consisted of the following:

(c) three $100 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2013 to December 11, 2014, from February 19, 2013 to February 19, 2014, and from February 19, 2014 to November 19, 2014, respectively;

(d) two $20 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate on the $20 million floating-rate notes maturing July 24, 2015, from January 24, 2013 to January 24, 2014, and from January 24, 2014 to January 24, 2015, respectively, and;

(e) a $20 million floating-to-fixed interest-rate swap agreement that locks in the floating-rate on the $20 million floating-rate notes maturing December 3, 2016, from December 3, 2013 to December 3, 2014.

At December 31, 2013 and 2012, the carrying amounts of derivative instruments were representative of fair value.

Fair Value Hierarchy

Fair value hierarchy information for financial assets and liabilities at December 31, 2013 and 2012 was as follows:

December 31, 2013 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	47	47	47	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	3	3	–	3	–
	50	50	47	3	–
Liabilities:					
Long-term debt	3,316	3,573	–	3,573	–
	3,316	3,573	–	3,573	–

December 31, 2012 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	5	5	5	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	5	5	–	5	–
	10	10	5	5	–
Liabilities:					
Long-term debt	3,015	3,543	–	3,543	–
	3,015	3,543	–	3,543	–

The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the un-hedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2013 and 2012.

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 Hydro One 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. This could be mirrored in the Company. The Company is exposed to fluctuations in interest rates as the regulated rate of return for its Distribution Business 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 Distribution Business' rate of return would reduce the Distribution Business' results of operations by approximately $10 million (2012 – $10 million).

Hydro One uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One also uses derivative financial instruments to manage interest-rate risk. Hydro One 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, Hydro One may utilize interest-rate derivative instruments 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. The Company's derivative instrument policy is consistent with Hydro One. No cash flow hedge agreements were outstanding as at December 31, 2013 or 2012.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in the Distribution Business' results of operations for the years ended December 31, 2013 or 2012.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instruments as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Distribution Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2013 and 2012 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Unrealized loss (gain) on hedged debt	(2)	(4)
Unrealized loss (gain) on fair value interest-rate swaps	2	4
Net unrealized loss (gain)	–	–

At December 31, 2013, the amount of the Distribution Business' fair value hedges outstanding related to interest-rate swaps was $200 million (2012 – $200 million), with assets at fair value of $3 million (2012 – $5 million). During the years ended December 31, 2013 and 2012, there was no significant impact on the Distribution Business' 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. At December 31, 2013 and 2012, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business did not earn a significant amount of revenue from any individual customer. At December 31, 2013 and 2012, there was no significant accounts receivable balance due from any single customer.

At December 31, 2013, the Distribution Business' allowance for doubtful accounts was $32 million (2012 – $20 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2013, approximately 4% of the Distribution Business' net accounts receivable were aged more than 60 days (2012 – 2%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Hydro One'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, Hydro One 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. Hydro One 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 Hydro One as specified in each agreement. Hydro One monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk policy is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on its Balance Sheets.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. The Company meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

At December 31, 2013, accounts payable and accrued liabilities in the amount of $651 million (2012 – $650 million) were expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2013, the principal amount of the Distribution Business' long-term debt was $3,313 million (2012 – $3,010 million). Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	**Principal Outstanding on Long-term Debt** *(millions of Canadian dollars)*	**Interest Payments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	175	154	3.2
2 years	220	148	2.9
3 years	200	138	4.4
4 years	195	133	5.2
5 years	338	123	2.8
	1,128	696	3.6
6 – 10 years	381	537	3.6
Over 10 years	1,804	1,588	5.5
	3,313	2,821	4.6

13. CAPITAL MANAGEMENT

The Distribution Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB.

The Distribution Business considers its capital structure to consist of excess of assets over liabilities, long-term debt, and the inter-company demand facility. The following table summarizes this capital structure:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Long-term debt payable within one year	176	230
Inter-company demand facility	(47)	(5)
	129	225
Long-term debt	3,140	2,785
Excess of assets over liabilities	2,465	2,319
Total capital	5,734	5,329

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2013 and 2012:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Excess of assets over liabilities, January 1	2,319	2,168
Net income	258	258
Payments to Hydro One to finance dividends	(112)	(107)
Excess of assets over liabilities, December 31	2,465	2,319

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. 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 supplementary pension plan obligation is included in post-retirement and post-employment benefit liability on the Balance Sheets.

Pension Benefits

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 represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Hydro One's annual Pension Plan contributions for 2013 of $160 million (2012 – $163 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2013 pensionable earnings. Hydro One's estimated annual Pension Plan contributions for 2014 are approximately $160 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

At December 31, 2013, based on the December 31, 2011 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $6,576 million (2012 – $6,507 million). The fair value of Pension Plan assets available for these benefits was $5,731 million (2012 – $4,992 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2013, the Distribution Business charged $36 million (2012 – $26 million) of post-retirement and post-employment benefit costs to operations, and capitalized $35 million (2012 – $28 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2013 were $24 million (2012 – $25 million). In addition, the associated post-retirement and post-employment benefits regulatory asset decreased by $8 million (2012 – increased by $110 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets within the following line items:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Accrued liabilities	22	22
Post-retirement and post-employment benefit liability	824	785
	846	807

15. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2013 and 2012:

Year ended December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	116	24	140
Interest accretion	6	–	6
Expenditures	(2)	(7)	(9)
Revaluation adjustment	(3)	18	15
Environmental liabilities, December 31	117	35	152
Less: current portion	7	6	13
	110	29	139

Year ended December 31, 2012 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	116	27	143
Interest accretion	6	–	6
Expenditures	(4)	(5)	(9)
Revaluation adjustment	(2)	2	–
Environmental liabilities, December 31	116	24	140
Less: current portion	3	5	8
	113	19	132

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheets after factoring in the discount rate:

December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	136	37	173
Less: discounting accumulated liabilities to present value	(19)	(2)	(21)
Discounted environmental liabilities	117	35	152

December 31, 2012 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	135	25	160
Less: discounting accumulated liabilities to present value	(19)	(1)	(20)
Discounted environmental liabilities	116	24	140

At December 31, 2013, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2014	13
2015	15
2016	22
2017	20
2018	19
Thereafter	84
	173

At December 31, 2013, of the total estimated future environmental expenditures, $136 million relates to PCBs (2012 – $135 million) and $37 million relates to LAR (2012 – $25 million).

The Distribution Business records a liability for the estimated future expenditures for the contaminated LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.3% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution Business' environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. The Distribution Business records a regulatory asset reflecting the expectation that future environmental costs will be recoverable in rates.

PCBs

In September 2008, Environment Canada published regulations governing the management, storage and disposal of PCBs, enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under these regulations and the Company's approved end-of-use extension, PCBs in concentrations of 500 parts per million (ppm) or more have to be disposed of by the end of 2014, with the exception of specifically exempted equipment, and PCBs in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts, must be disposed of by the end of 2025. Management judges that the Distribution Business currently has very few PCB-contaminated assets in excess of 500 ppm. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $136 million. These expenditures are expected to be incurred over the period from 2014 to 2025. As a result of the Company's annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2013 to reduce the PCB environmental liability by $3 million (2012 – $2 million).

LAR

The Distribution Business' best estimate of the total estimated future expenditures to complete its LAR program is $37 million. These expenditures are expected to be incurred over the period from 2014 to 2022. As a result of the Company's annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2013 to increase the LAR environmental liability by $18 million (2012 – $2 million).

16. ASSET RETIREMENT OBLIGATIONS

The Company records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution Business' AROs represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. AROs are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2013, the Company had recorded AROs of $4 million (2012 – $3 million), related to its Distribution Business, consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations in 2013.

17. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks has 14,875,720 issued and outstanding cumulative preferred shares and 148,821,741 issued and outstanding common shares. The Company is authorized to issue an unlimited number of preferred shares and common shares.

Hydro One Networks makes common share and preferred share dividend payments to Hydro One. The Distribution Business makes payments to finance its share of the Company's common share and preferred share dividends. During 2013, the Distribution Business' payments to finance these dividends totaled $112 million (2012 – $107 million).

18. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of a subsidiary of Hydro One, and 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 the Distribution Business because they are controlled or significantly influenced by the Province. Transactions between these parties and the Distribution Business are described below.

The Distribution Business receives amounts for rural rate protection from the IESO. 2013 revenues include $125 million (2012 – $125 million) related to this program.

In 2013, the Distribution Business purchased power in the amount of $2,077 million (2012 – $2,031 million) from the IESO-administered electricity market, $15 million (2012 – $10 million) from OPG, and $8 million (2012 – $7 million) from power contracts administered by 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 transmitters. In 2013, the Distribution Business incurred $6 million (2012 – $6 million) in OEB fees.

The Company has service level agreements with OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs of the Distribution Business related to the purchase of services with respect to these service level agreements were less than $1 million in both 2013 and 2012.

The OPA funds substantially all of the Company's conservation and demand management programs. The funding includes program costs, incentives, and management fees. In 2013, the Distribution Business received $26 million (2012 – $32 million) from the OPA related to these programs.

Hydro One pays a $5 million annual fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999. The Distribution Business' allocation of this fee is $1 million.

PILs and payments in lieu of property taxes were paid or payable to the OEFC.

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

December 31 (millions of Canadian dollars)	**2013**	**2012**
Accounts receivable	56	32
Accrued liabilities[1]	(189)	(185)

[1] Included in accrued liabilities at December 31, 2013 are amounts owing to the IESO in respect of power purchases of $185 million (2012 – $172 million).

Hydro One and Subsidiaries

The Distribution Business provides services to, and receives services from, Hydro One and its subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of shared corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2013 revenues of the Distribution Business include $3 million (2012 – $2 million) related to the provision of services to Hydro One and its subsidiaries. Operation, maintenance and administration costs of the Distribution Business include $12 million (2012 – $11 million) related to the services received from Hydro One and its subsidiaries.

The Distribution Business' long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or due from Hydro One. Financing charges include interest expense on the long-term debt in the amount of $150 million (2012 – $154 million), and interest income on the inter-company demand facility in the amount of $1 million (2012 – interest expense of $2 million). At December 31, 2013, the Distribution Business had accrued interest payable to Hydro One totaling $38 million (2012 – $35 million).

19. STATEMENTS OF CASH FLOWS

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

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Accounts receivable	(75)	(34)
Materials and supplies	1	(3)
Other assets	1	(5)
Accounts payable	9	8
Accrued liabilities	(4)	(53)
Accrued interest	3	4
Long-term accounts payable and other liabilities	(12)	9
Post-retirement and post-employment benefit liability	47	29
	(30)	(45)

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Capital investments in property, plant and equipment	(572)	(562)
Net change in accruals included in capital investments in property, plant and equipment	(7)	–
Capital expenditures – property, plant and equipment	(579)	(562)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Capital investments in intangible assets	(65)	(74)
Net change in accruals included in capital investments in intangible assets	(1)	1
Capital expenditures – intangible assets	(66)	(73)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Net interest paid	144	150
PILs	41	81

20. CONTINGENCIES

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available for the satisfaction of the debts, contingent liabilities and commitments of both the Company and Hydro One.

21. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

22. SUBSEQUENT EVENTS

On January 29, 2014, Hydro One issued $50 million notes under its MTN Program, with a maturity date of January 29, 2064 and a coupon rate of 4.29%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt, of which $20 million was allocated to the Company's Distribution Business.

On March 21, 2014, Hydro One issued $125 million floating-rate notes under its MTN Program, with a maturity date of March 21, 2019. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt, of which $50 million was allocated to the Company's Distribution Business.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2012

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying financial statements of the Distribution Business (a business of Hydro One Networks Inc.), which comprise the balance sheets as at December 31, 2012, and December 31, 2011, the statements of operations and comprehensive income, and cash flows for the year ended December 31, 2012, and December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information. The financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to these financial statements.

Management's Responsibility for the Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these financial statements in accordance with the basis of accounting in Note 2 to these financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Distribution Business (a business of Hydro One Networks Inc.) as at December 31, 2012, and December 31, 2011, and its statements of operations and comprehensive income, and cash flows for the year ended December 31, 2012, and December 31, 2011, in accordance with basis of accounting as set out in note 2 to these financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to these financial statements, which describes the basis of accounting and composition of Hydro One Networks Inc.'s Distribution Business. In particular, in preparing these financial statements, long-term debt, shared functions and services costs, and payments in lieu of corporate income taxes have been allocated to the Distribution Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to these financial statements. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position, results of operations and cash flows that would have resulted had the Distribution Business (a business of Hydro One Networks Inc.) historically operated as a stand-alone basis. These financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, these financial statements may not be suitable for another purpose. Our report is intended solely for Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Accountants, Licensed Public Accountants
Toronto, Canada
April 18, 2013

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	**2012**	**2011**
Revenues		*(Note 22)*
Energy sales	3,536	3,398
Rural rate protection *(Note 18)*	125	125
Other	53	46
	3,714	3,569
Costs		
Purchased power *(Note 18)*	2,413	2,285
Operation, maintenance and administration *(Note 18)*	553	555
Depreciation and amortization *(Note 4)*	308	287
	3,274	3,127
Income before financing charges and provision for payments in lieu of corporate income taxes	440	442
Financing charges *(Notes 5, 18)*	138	140
Income before provision for payments in lieu of corporate income taxes	302	302
Provision for payments in lieu of corporate income taxes *(Notes 6, 18)*	44	66
Net income	258	236
Other comprehensive income	-	-
Comprehensive income	258	236

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS

December 31 (millions of dollars)	**2012**	**2011**
Assets		*(Note 22)*
Current assets:		
Inter-company demand facility *(Notes 12, 13, 18)*	5	141
Accounts receivable (net of allowance for doubtful accounts - $20; 2011 - $15) *(Notes 7,18)*	778	744
Regulatory assets *(Note 10)*	14	9
Materials and supplies	7	4
Deferred income tax assets *(Note 6)*	7	8
Other	12	7
	823	913
Property, plant and equipment *(Note 8)*:		
Property, plant and equipment in service	8,363	7,863
Less: accumulated depreciation	3,078	2,870
	5,285	4,993
Construction in progress	314	293
Future use land, components and spares	45	39
	5,644	5,325
Other long-term assets:		
Regulatory assets *(Note 10)*	612	431
Intangible assets (net of accumulated amortization - $178; 2011 - $154) *(Note 9)*	159	108
Goodwill	73	73
Deferred debt costs	12	11
Derivative instruments *(Note 12)*	5	9
	861	632
Total assets	7,328	6,870

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)

December 31 (millions of dollars)	**2012**	**2011**
Liabilities		*(Note 22)*
Current liabilities:		
Accounts payable	58	49
Accrued liabilities *(Notes 6, 14, 15, 18)*	592	643
Accrued interest *(Note 18)*	35	31
Regulatory liabilities *(Note 10)*	38	16
Long-term debt payable within one year *(Notes 11, 12, 13, 18)*	230	324
	953	1,063
Long-term debt *(Notes 11, 12, 13, 18)*	2,785	2,565
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	785	646
Deferred income tax liabilities *(Note 6)*	230	171
Environmental liabilities *(Note 15)*	132	134
Regulatory liabilities *(Note 10)*	96	105
Net unamortized debt premiums	12	11
Asset retirement obligations *(Note 16)*	3	3
Long-term accounts payable and other liabilities	13	4
	1,271	1,074
Total liabilities	5,009	4,702
Contingencies and commitments (Notes 20, 21)		
Excess of assets over liabilities *(Notes 13, 17)*	2,319	2,168
Total liabilities and excess of assets over liabilities	7,328	6,870

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Carmine Marcello
Chair

Sandy Struthers
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2012**	**2011**
Operating activities		*(Note 22)*
Net income	258	236
Environmental expenditures	(9)	(8)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	262	242
Regulatory assets and liabilities	(5)	40
Deferred income taxes	2	(9)
Other	1	1
Changes in non-cash balances related to operations *(Note 19)*	(44)	128
Net cash from operating activities	465	630
Financing activities		
Long-term debt issued	454	225
Long-term debt retired	(324)	(176)
Payments to Hydro One Inc. to finance dividends	(107)	(45)
Other	-	(1)
Net cash from financing activities	23	3
Investing activities		
Capital expenditures		
Property, plant and equipment	(562)	(539)
Intangible assets	(74)	(57)
Other	12	18
Net cash used in investing activities	(624)	(578)
Net change in inter-company demand facility	(136)	55
Inter-company demand facility, beginning of year	141	86
Inter-company demand facility, end of year	5	141

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) 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.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP). These Financial Statements are to be read in conjunction with Note 22 - Transition to US GAAP, which discloses information on the Canadian GAAP, per Part V of the Canadian Institute of Chartered Accountants Handbook (Canadian GAAP), to US GAAP transition and related reconciliations from Canadian GAAP to US GAAP. The results of operations for the year ended December 31, 2011, and the Balance Sheets as at December 31, 2011 have been restated under US GAAP for comparative purposes.

These Financial Statements have been prepared for the specific use of the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2012 have been prepared and are publicly available.

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Distribution Business on a basis approved by the OEB. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company's Distribution Business. As a result of this basis of accounting, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Payments in lieu of corporate income taxes (PILs) have been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Distribution Business was a separate taxpaying entity. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events for the accompanying Financial Statements and notes included through to April 18, 2013, the date these Financial Statements were available to be issued, to determine whether the circumstances warranted recognition and disclosure of any events or transactions. No such events or transactions were identified.

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, expenses, gains and losses 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 assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill, asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, 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 OEB has approved the Company's request to use US GAAP as the basis for rate setting and regulatory accounting and reporting for its Distribution Business, effective January 1, 2012.

In 2009, Hydro One Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $1,264 million. The application reflected the Company's plan to invest in its network assets to meet objectives regarding public and employee safety, regulatory and legislative compliance, maintenance of system security and reliability of system growth requirements, and to make investments required by the Green Energy Act. In April 2010, the OEB approved a revenue requirement of $1,236 million for 2011. The OEB also approved certain distribution regulatory account balances sought by Hydro One Networks in its application, including retail settlement variance accounts, retail cost variance accounts and smart meters. In November 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. A lowering of the return on equity produced a revised revenue requirement of $1,218 million. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year.

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 Distribution Business' 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 Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to electricity customers. The Distribution Business 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 Distribution Business 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

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 electricity 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 are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount or net realizable value, if unbilled. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Distribution Business' best estimate of losses on accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Distribution Business 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.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One Networks is required to remit 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% 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 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 Financial Statements and their 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 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 realized.

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

The Distribution Business uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only the ITCs are recognized as a reduction to income tax expense.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

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

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, 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 Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized 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 costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of 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.

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 amounts incurred to acquire land rights and other access rights.

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), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Distribution Business' intangible assets primarily represent major administrative computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs directly attributable to the construction of property, plant and equipment or development of intangible assets. The financing 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 Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Distribution Businesss' weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of assets that are not yet complete 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, except for transport and work equipment, which is depreciated on a declining balance basis.

Hydro One 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 OEB approval of 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	Average
Distribution	42 years	1% - 5%	2%
Communication	11 years	1% - 13%	5%
Administration and service	17 years	1% - 15%	8%

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

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 and amortization, 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 such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment assets where no ARO has been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate-base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Per Accounting Standards Update (ASU) 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment, issued by the Financial Accounting Standards Board (FASB) in September 2011, the Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a 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.

For the year ended December 31, 2012, based on the qualitative assessment performed, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 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.

The carrying costs of most of the Distribution Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2012, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the 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 within financing charges in the Statements of Operations and Comprehensive Income. 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 amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges, and the change in fair value on the Company's proportionate share of existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its share of unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the allocated hedged debt. OCI and net income are presented in a single continuous 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. Hydro One Networks 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 its risk management policy disclosed in Note 12 – Fair Value of Financial Instruments and Risk Management.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various derivative 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. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

The accounting guidance for derivative instruments 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 Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized in its 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, net of tax, is reported as a component of accumulated OCI (AOCI) and is 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 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 Statements of Operations and Comprehensive Income. Additionally, Hydro One 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 derivative instruments are separated from their host contracts and carried at fair value on the 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. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2012.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where Hydro One has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly 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 pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One 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. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets. For the year ended December 31, 2012, the measurement date for the Plans was December 31.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

A detailed description of Hydro One pension benefits is provided in Note 14 - Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2012.

Post-retirement and post-employment benefits

The Company records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded on transition to US GAAP and at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for 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 post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates 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.

For post-retirement benefits, 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. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment 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.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in Note 14 - Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2012.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Distribution Business' 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. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Distribution Business 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 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 Distribution Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each 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 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. The Distribution Business records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 present value is determined 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 it is anticipated 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. The estimates of future environmental expenditures are reviewed 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. Where an asset is no longer in-service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some 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 Distribution Business 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 Distribution Business' 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

Recently Adopted Accounting Pronouncements

In September 2011, the FASB issued ASU 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment. This ASU 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 adoption of this ASU did not have a significant impact on the Distribution Business' Financial Statements.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income, 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 ASU do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. The Distribution Business has elected to present OCI and net income in a single continuous Statement of Operations and Comprehensive Income.

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 US GAAP and IFRSs. This 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. This ASU is largely consistent with existing US GAAP fair value measurement principles under Accounting Standards Codification 820. However, this 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 Balance Sheets but for which the fair value is required to be disclosed. Required disclosures have been included in Note 12 – Fair Value of Financial Instruments and Risk Management. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Distribution Business' Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the Balance Sheets as well as financial 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 ASU only requires enhanced disclosures, the adoption of this ASU is not anticipated to have a significant impact on the Distribution Business' Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of dollars)	**2012**	**2011**
Depreciation of property, plant and equipment	229	212
Amortization of intangible assets	24	22
Asset removal costs	46	45
Amortization of regulatory assets	9	8
	308	287

5. FINANCING CHARGES

Year ended December 31 (millions of dollars)	**2012**	**2011**
Interest on long-term debt	154	152
Other	8	4
Less: Interest capitalized on construction and development in progress	(18)	(11)
Gain on interest-rate swap agreements	(4)	(3)
Interest earned on inter-company demand facility	(2)	(2)
	138	140

6. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Income before provision for PILs	302	302
Canadian Federal and Ontario statutory income tax rate	26.50%	28.25%
Provision for PILs at statutory rate	80	85
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(8)	(4)
Interest capitalized for accounting but deducted for tax purposes	(4)	(3)
Pension contributions in excess of pension expense	(12)	(10)
Overheads capitalized for accounting but deducted for tax purposes	(6)	(5)
Environmental expenditures	(2)	(2)
Non-refundable ITCs	(6)	-
Post-retirement and post-employment benefit expense in excess of cash payments	-	3
Other	1	1
Net temporary differences	(37)	(20)
Net permanent differences	1	1
Total provision for PILs	44	66
Current provision for PILs	42	75
Deferred provision for PILs	2	(9)
Total provision for PILs	44	66
Effective income tax rate	14.57%	21.85%

The current provision for PILs of $42 million (2011 - $75 million) represents the amount paid or payable to the OEFC with respect to current year income. The outstanding balance due to the OEFC at December 31, 2012 was $7 million (2011 - $30 million).

The total provision for PILs includes deferred provision for PILs of $2 million (2011 - recovery of $9 million) that is 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.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	290	200
Environmental expenses	36	36
Other	1	1
Total deferred income tax assets	327	237
Less: current portion	10	10
	317	227

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	458	374
Distribution amounts received but not recognized for accounting purposes	84	19
Goodwill	8	7
Total deferred income tax liabilities	550	400
Less: current portion	3	2
	547	398

The deferred income tax assets and liabilities are presented on the Balance Sheets as follows:

December 31 (millions of dollars)	**2012**	**2011**
Current deferred income tax assets	10	10
Current deferred income tax liabilties	(3)	(2)
Net current deferred income tax assets	7	8
Long-term deferred income tax assets	317	227
Long-term deferred income tax liabilities	(547)	(398)
Net long-term deferred income tax liabilities	(230)	(171)

During 2012, the deferred tax liability increased by $14 million as a result of the change in the rate applicable to future taxes.

7. ACCOUNTS RECEIVABLE

December 31 (millions of dollars)	**2012**	**2011**
Accounts receivable – billed	200	214
Accounts receivable – unbilled	598	545
Accounts receivable, gross	798	759
Allowance for doubtful accounts	(20)	(15)
Accounts receivable, net	778	744

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2012 and 2011.

Year ended December 31 (millions of dollars)	**2012**	**2011**
Allowance for doubtful accounts – January 1	(15)	(22)
Write-offs	16	29
Additions to allowance for doubtful accounts	(21)	(22)
Allowance for doubtful accounts – December 31	(20)	(15)

8. PROPERTY, PLANT AND EQUIPMENT

December 31 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
2012				
Distribution	7,476	2,602	220	5,094
Communication	100	21	-	79
Administration and Service	824	451	94	467
Easements	8	4	-	4
	8,408	3,078	314	5,644
2011				
Distribution	7,090	2,440	243	4,893
Communication	30	16	-	14
Administration and Service	774	410	50	414
Easements	8	4	-	4
	7,902	2,870	293	5,325

Financing charges capitalized on property, plant and equipment under construction were $15 million (2011 - $10 million).

9. INTANGIBLE ASSETS

December 31 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2012				
Computer applications software	228	176	107	159
Other assets	2	2	-	-
	230	178	107	159
2011				
Computer applications software	217	153	44	108
Other assets	1	1	-	-
	218	154	44	108

Financing charges capitalized on intangible assets under development were $3 million (2011 - $1 million). The estimated annual amortization expense for intangible assets for each of the next five years is $21 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 (millions of dollars)	**2012**	**2011**
Regulatory assets:		
Deferred income tax	239	181
Post-retirement and post-employment benefits	180	70
Environmental	140	142
Pension cost variance	46	29
Rider 2	10	11
Other	11	7
Total regulatory assets	626	440
Less: current portion	14	9
	612	431
Regulatory liabilities:		
Retail settlement variance accounts	46	40
Rider 8	45	42
PST savings deferral	10	6
Rider 3	9	9
Deferred income tax	7	7
Rural and remote rate protection variance	6	8
Other	11	9
Total regulatory liabilities	134	121
Less: current portion	38	16
	96	105

Deferred Income Tax

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Distribution Business has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-making process. In the absence of rate-regulated accounting, the Distribution Business' provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be reflected in future rates. As a result, the 2012 provision for PILs would have been higher by approximately $41 million (2011 - $22 million), including the impact of a change in enacted tax rates.

Post-Retirement and Post-Employment Benefits

The Distribution Business recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $110 million (2011 – higher by $16 million).

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 15 – Environmental Liabilities). Because such expenditures are expected to be recoverable in future rates, the Distribution Business has recorded an equivalent amount as a regulatory asset. In 2012, the Company's PCB liability decreased by $2 million (2011 - $23 million) to reflect a revaluation adjustment in the Company's PCB liability and increased by $2 (2011 – no change) for a revision to the Company's LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, there would have been no change in 2012 operation, maintenance and administration expenses (2011 – lower by $23 million). In addition, 2012 amortization expense would have been lower by $9 million (2011 – $8 million), and 2012 financing charges would have been higher by $6 million (2011 – $8 million).

Pension Cost Variance

A pension cost variance account was established for the Distribution Business to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension contributions as compared to OEB-approved amounts. In December 2010, the OEB approved the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, 2012 revenue would have been lower by $17 million (2011 - $13 million).

Rider 2

In April 2006, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by the Company. The Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

Retail Settlement Variance Accounts (RSVA)

The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In April 2010, the OEB approved the disposition of the total RSVA balance accumulated from May 2008 to December 2009, including accrued interest, to be disposed over a 20-month period from May 1, 2010 to December 31, 2011. The Company has continued to accumulate a net liability in its RSVA accounts since December 31, 2009.

Rider 8

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost of service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administrative expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable and calculations for tracking and refund were requested by the OEB. For the Distribution Business, PST was included in rates between July 1, 2010 and December 31, 2012 and this amount has been recorded in a deferral account per direction from the OEB.

Rider 3

In December 2008, the OEB approved certain distribution-related deferral account balances sought by the Company, including RSVA amounts, deferred tax changes, OEB costs and smart meters. The OEB approved the disposition of the Rider 3 balance accumulated up to April 2008, including accrued interest, to be disposed over a 27-month period from February 1, 2009 to April 30, 2011.

Rural and Remote Rate Protection Variance (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. The OEB has approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked in the RRRP variance account.

11. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, which is then allocated between the Company's transmission and distribution businesses.

The following table presents the outstanding long-term debt of the Distribution Business as at December 31, 2012 and 2011:

December 31 (millions of dollars)	**2012**	**2011**
Long-term debt	3,010	2,880
Add: Unrealized marked-to-market loss[1]	5	9
Less: Long-term debt payable within one year	(230)	(324)
Long-term debt	2,785	2,565

[1] The unrealized marked-to-market loss relates to $100 million of Distribution Business' $175 million note due 2014, and $100 million of Distribution Business' $200 million note due 2015. The unrealized marked-to-market loss is offset by a $5 million (2011 - $9 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 12 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 12 – Fair Value of Financial Instruments and Risk Management.

12. 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.

The Company 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

At December 31, 2012 and 2011, the carrying amounts of accounts receivable, inter-company demand facility, 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 Distribution Business' long-term debt at December 31, 2012 and 2011 are as follows:

December 31 (millions of dollars)	2012 Carrying Value	2012 Fair Value	2011 Carrying Value	2011 Fair Value
Long-term debt				
$100 million of $175 million notes due 2014[1]	102	102	104	104
$100 million of $200 million notes due 2015[2]	103	103	105	105
Other notes and debentures[3]	2,810	3,338	2,680	3,180
	3,015	3,543	2,889	3,389

[1] The fair value of $100 million of Distribution Business' $175 million notes due 2014, 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 $100 million of Distribution Business' $200 million notes due 2015, 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 Distribution Business' $175 million and $200 million notes 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 Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

At December 31, 2012, the Distribution Business' share of the Company's derivative instruments include $200 million of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt (2011 - $200 million). These interest-rate swaps are classified as fair value hedges. The Distribution Business' fair value hedge exposure was equal to about 7% (2011 – 7%) of its long-term debt. At December 31, 2012, the Distribution Business' interest-rate swaps designated as fair value hedges were as follows:

(a) a $100 million fixed-to-floating interest-rate swap agreement to convert $100 million of the $175 million notes maturing November 19, 2014 into three-month variable rate debt; and

(b) two $50 million fixed-to-floating interest-rate swap agreements to convert $100 million of the $200 million notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2012, the Distribution Business' share of interest-rate swaps classified as undesignated contracts consisted of the following:

(c) three $100 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2012 to December 11, 2013, from February 21, 2012 to February 19, 2013, and from February 19, 2013 to February 19, 2014, respectively;

(d) two $20 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate on the $20 million floating-rate notes maturing July 24, 2015, from January 24, 2012 to January 24, 2013, and from January 24, 2013 to January 24, 2014, respectively, and;

(e) a $20 million floating-to-fixed interest-rate swap agreement that locks in the floating-rate on the $20 million floating-rate notes maturing December 3, 2016, from March 4, 2013 to December 3, 2013.

At December 31, 2012 and 2011, the carrying amounts of derivative instruments were representative of fair value.

Fair Value Hierarchy

Fair value hierarchy information for financial assets and liabilities at December 31, 2012 and 2011 was as follows:

December 31, 2012 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	5	5	5	-	-
Derivative instruments					
Fair value hedges – interest-rate swaps	5	5	-	5	-
	10	10	-	10	-
Liabilities:					
Long-term debt	3,015	3,543	-	3,543	-
	3,015	3,543	-	3,543	-

December 31, 2011 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	141	141	141	-	-
Derivative instruments					
Fair value hedges – interest-rate swaps	9	9	-	9	-
	150	150	141	9	-
Liabilities:					
Long-term debt	2,889	3,389	-	3,389	-
	2,889	3,389	-	3,389	-

The fair value of the derivative instruments is determined using other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the un-hedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2012 and 2011.

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 Hydro One 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. This could be mirrored in the Company. The Company is exposed to fluctuations in interest rates as the regulated rate of return for its Distribution Business 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 Distribution Business' rate of return would reduce the Distribution Business' results of operations by approximately $10 million (2011 - $10 million).

Hydro One uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One also uses derivative financial instruments to manage interest-rate risk. Hydro One 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, Hydro One may utilize interest-rate derivative instruments 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. The Company's derivative instrument policy is consistent with Hydro One. No cash flow hedge agreements outstanding as at December 31, 2012 or 2011.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in the Distribution Business' results of operations for the years ended December 31, 2012 or 2011.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instruments as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Distribution Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2012 and 2011 are included in financing charges as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Unrealized (gain) loss on hedged debt	(4)	7
Unrealized loss (gain) on fair value interest-rate swaps	4	(7)
Net unrealized loss (gain)	-	-

At December 31, 2012, the notional amount of the Distribution Business' fair value hedges outstanding related to interest-rate swaps was $200 million (2011 - $200 million), with assets at fair value of $5 million (2011 - $9 million). During the years ended December 31, 2012 and 2011, there was no significant impact on the Distribution Business' 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. At December 31, 2012 and 2011, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business did not earn a significant amount of revenue from any individual customer. At December 31, 2012 and 2011, there was no significant accounts receivable balance due from any single customer.

At December 31, 2012, the Distribution Business' allowance for doubtful accounts was $20 million (2011 - $15 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2012, approximately 2% of the Distribution Business' accounts receivable were aged more than 60 days (2011 - 1%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Hydro One'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, Hydro One 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. Hydro One 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 Hydro One as specified in each agreement. Hydro One monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk policy is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on its 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 December 31, 2012, the counterparty credit risk exposure on the fair value of the Distribution Business' share of these interest-rate swap contracts was $6 million (2011 - $10 million). At December 31, 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.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. The Company meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

At December 31, 2012, accounts payable and accrued liabilities in the amount of $650 million (2011 - $692 million) were expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2012, the notional amount of the Distribution Business' long-term debt was $3,010 million (2011 – $2,880 million). Long-term debt maturing over the next twelve months was $230 million (2011 - $324 million). Interest payments for the next 12 months on the outstanding long-term debt were $146 million (2011 – $150 million). Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table.

Years to Maturity	Principal Outstanding on Long-term Debt	Interest Payments[1]	Weighted Average Interest Rate[1]
	(millions of dollars)	*(millions of dollars)*	*(%)*
1 year	230	146	5.0
2 years	175	135	3.2
3 years	220	129	2.9
4 years	200	119	4.4
5 years	195	115	5.2
	1,020	644	4.1
6 - 10 years	381	506	3.6
Over 10 years	1,609	1,498	5.7
	3,010	2,648	4.9

[1] Interest payments and weighted average interest rates beyond one year exclude the impact of Distribution Business' $20 million floating-rate notes due 2015 and Distribution Business' $20 million floating-rate notes due 2016.

13. CAPITAL MANAGEMENT

The Distribution Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB.

The Distribution Business considers its capital structure to consist of excess of assets over liabilities, long-term debt, and the inter-company demand facility. The following table summarizes this capital structure:

December 31 (millions of dollars)	**2012**	**2011**
Long-term debt payable within one year	230	324
Inter-company demand facility	(5)	(141)
	225	183
Long-term debt	2,785	2,565
Excess of assets over liabilities	2,319	2,168
Total capital	5,329	4,916

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2012 and 2011:

December 31 (millions of dollars)	**2012**	**2011**
Excess of assets over liabilities, January 1	2,168	1,976
Net income	258	236
OCI	-	-
Payments to Hydro One to finance dividends	(107)	(45)
Excess of assets over liabilities, December 31	2,319	2,168

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. 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 supplementary pension plan obligation is included in post-retirement and post-employment benefit liability on the Balance Sheets.

Pension Benefits

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 represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Hydro One's annual Pension Plan contributions for 2012 of $163 million (2011 – $152 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2012 pensionable earnings. Hydro One's estimated annual Pension Plan contributions for 2013 are approximately $160 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

At December 31, 2012, based on the December 31, 2011 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $6,507 million (2011 - $5,461 million). The fair value of Pension Plan assets available for these benefits was $4,992 million (2011 - $4,682 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2012, the Distribution Business charged $26 million (2011 – $33 million) of post-retirement and post-employment benefit costs to operations, and capitalized $28 million (2011 - $23 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2012 were $25 million (2011 - $23 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was increased by $110 million (2011 – decreased by $15 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets within the following line items:

December 31 (millions of dollars)	**2012**	**2011**
Accrued liabilities	22	22
Post-retirement and post-employment benefit liability	785	646
	807	668

15. ENVIRONMENTAL LIABILITIES

The following discounted amounts for environmental liabilities were recorded on the Balance Sheets at December 31, 2012 and 2011:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Environmental liabilities, January 1	116	27	143
Interest accretion	6	-	6
Expenditures	(4)	(5)	(9)
Revaluation adjustment	(2)	2	-
Environmental liabilities, December 31	116	24	140
Less: current portion	3	5	8
	113	19	132

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Environmental liabilities, January 1	135	31	166
Interest accretion	7	1	8
Expenditures	(3)	(5)	(8)
Revaluation adjustment	(23)	-	(23)
Environmental liabilities, December 31	116	27	143
Less: current portion	5	4	9
	111	23	134

The following table illustrates the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized in the Balance Sheets after factoring in the discount rate:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Undiscounted environmental liabilities, December 31	135	25	160
Less: discounting accumulated liabilities to present value	(19)	(1)	(20)
Discounted environmental liabilities, December 31	116	24	140

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Undiscounted environmental liabilities, December 31	138	28	166
Less: discounting accumulated liabilities to present value	(22)	(1)	(23)
Discounted environmental liabilities, December 31	116	27	143

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2012 and in total thereafter are as follows: 2013 - $9 million; 2014 - $22 million; 2015 - $22 million; 2016 - $19 million; 2017 - $15 million; and thereafter - $73 million. At December 31, 2012, of the total estimated future environmental expenditures, $135 million related to PCB (2011 - $138 million) and $25 million related to LAR (2011 - $28 million).

Consistent with the Company's accounting policy for environmental costs, the Distribution Business records a liability for the estimated mandatory future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment and for the assessment and remediation of chemically-contaminated lands.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Distribution Business' environmental liabilities represent management's best estimates of the present value of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively. The Distribution Business records a regulatory asset reflecting its expectation that future environmental costs will be recoverable in rates.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. The Distribution Business' future environmental expenditures have been discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

PCBs

In September 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. These regulations impose timelines for disposal of PCBs based on certain criteria, including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except for specified equipment, had to be disposed of by the end of 2009, with the exception of specifically exempted equipment. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025.

Management judges that the Distribution Business currently has very few PCB-contaminated assets in excess of 500 ppm. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains a PCB concentration of less than 2 ppm.

The Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is approximately $135 million. These expenditures are expected to be incurred over the period from 2013 to 2025. As a result of the Company's most recent cost estimate to comply with current PCB regulations, the Distribution Business recorded a revaluation adjustment to reduce the PCB environmental liability by approximately $2 million (2011 – $23 million).

LAR

The Distribution Business' best estimate of the total estimated future expenditures to complete its LAR Program is approximately $25 million. These expenditures are expected to be incurred over the period from 2013 to 2020. As part of its annual review of environmental liabilities, the Company also reviewed its liability for LAR. As a result of this review, the Distribution Business recorded a revaluation adjustment to increase the LAR environmental liability by approximately $2 million (2011 - $nil).

16. ASSET RETIREMENT OBLIGATIONS

AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO (with corresponding adjustments to property, plant, and equipment), which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired and changes in federal, state or local regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

All factors used in estimating the Distribution Business' AROs represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the current assumptions. AROs are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for completing required removal and remediation work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3% to 5%, depending on the appropriate rate for the period when expenditures are expected to be incurred.

At December 31, 2012, the Company had recorded AROs of $3 million (2011 – $3 million) related to its Distribution Business, consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

The Company's liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities is based on management's best estimate of the present value of the estimated future expenditures to comply with current regulations. In 2010, the Company completed a study with the aid of an external expert to estimate the future expenditures required to remove asbestos prior to facility demolition.

17. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks has 14,875,720 issued and outstanding cumulative preferred shares and 148,821,741 issued and outstanding common shares. The Company is authorized to issue an unlimited number of preferred shares and common shares.

Hydro One Networks makes common share and preferred share dividend payments to Hydro One. The Distribution Business makes payments to finance its share of the Company's common share and preferred share dividends. During 2012, the Distribution Business' payments to finance these dividends totaled $107 million (2011 - $45 million).

18. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of a subsidiary of Hydro One, and 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 the Distribution Business because they are controlled or significantly influenced by the Province. Transactions between these parties and the Distribution Business are described below.

The Distribution Business receives amounts for rural rate protection from the IESO. 2012 revenues include $125 million (2011 – $125 million) related to this program.

In 2012, the Distribution Business purchased power in the amount of $2,031 million (2011 - $2,057 million) from the IESO-administered electricity market, $10 million (2011 - $16 million) from OPG, and $7 million (2011 - $10 million) from 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. In 2012, the Distribution Business incurred $6 million (2011 - $7 million) in OEB fees.

The Company has service level agreements with OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs of the Distribution Business related to the purchase of services with respect to these service level agreements were less than $1 million in both 2012 and 2011.

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 2012, the Distribution Business received $32 million (2011 - $38 million) from the OPA related to these CDM programs.

PILs were paid or payable to the OEFC.

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

December 31 (millions of dollars)	2012	2011
Accounts receivable	32	36
Accrued liabilities[1]	(184)	(237)

[1] Included in accrued liabilities at December 31, 2012 are amounts owing to the IESO in respect of power purchases of $172 million (2011 – $182 million).

Hydro One and Subsidiaries

The Distribution Business provides services to, and receives services from, Hydro One and its subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of shared corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2012 revenues of the Distribution Business include $2 million (2011 - $2 million) related to the provision of services to Hydro One and its subsidiaries. Operation, maintenance and administration costs of the Distribution Business include $11 million (2011 - $10 million) related to the services received from Hydro One and its subsidiaries.

The Distribution Business' long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or due from Hydro One. Financing charges include interest expense on the long-term debt in the amount of $154 million (2011 - $152 million), and interest income on the inter-company demand facility in the amount of $2 million (2011 - $2 million). At December 31, 2012, the Distribution Business had accrued interest payable to Hydro One totaling $35 million (2011 - $31 million).

19. STATEMENTS OF CASH FLOWS

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

Year ended December 31 (millions of dollars)	**2012**	**2011**
Accounts receivable	(34)	(34)
Materials and supplies	(3)	1
Other assets	(5)	(4)
Accounts payable	9	6
Accrued liabilities	(53)	123
Accrued interest	4	-
Long-term accounts payable and other liabilities	9	-
Post-retirement and post-employment benefit liability	29	33
	(44)	125

Supplementary information:		
Net interest paid	150	152
PILs	81	31

20. CONTINGENCIES

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available for the satisfaction of the debts, contingent liabilities and commitments of both the Company and Hydro One.

21. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

22. 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. The Distribution Business' transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to its 2012 Financial Statements.

Measurement and classification differences resulting from the Distribution Business' 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 Balance Sheets 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. Balance Sheets 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 resulting from the Distribution Business' adoption of US GAAP on the 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 Canadian GAAP 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 to total assets:

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total assets – Canadian GAAP		6,344	6,789
Deferred debt costs	A	11	11
Regulatory assets	B	86	70
Total assets – US GAAP		6,441	6,870

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

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total liabilities – Canadian GAAP		4,368	4,621
Long-term debt	A	(2)	-
Net unamortized debt premiums	A	13	11
Post-retirement and post-employment benefit liability	B	86	70
Total liabilities – US GAAP		4,465	4,702

US GAAP Differences

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

January 1, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Inter-company demand facility		86	-	86
Accounts receivable		710	-	710
Regulatory assets		25	-	25
Materials and supplies		5	-	5
Deferred income tax assets		12	-	12
Other		2	-	2
		840	-	840
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		4,707	-	4,707
Construction in progress		269	-	269
Future use land, components and spares		39	-	39
		5,015	-	5,015
Other long-term assets:				
Regulatory assets	B	338	86	424
Intangible assetss (net of accumulated amortization)		76	-	76
Goodwill		73	-	73
Deferred debt costs	A	-	11	11
Derivative instruments	C	-	1	1
Other	C	2	(1)	1
		489	97	586
Total assets		6,344	97	6,441
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	D	561	(561)	-
Accounts payable	D	-	43	43
Accrued liabilities	D	-	518	518
Accrued interest		31	-	31
Regulatory liabilities		47	-	47
Long-term debt payable within one year		176	-	176
		815	-	815
Long-term debt	A	2,658	(2)	2,656
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	543	86	629
Deferred income tax liabilities		154	-	154
Environmental liabilities		157	-	157
Regulatory liabilities		34	-	34
Net unamortized debt premiums	A	-	13	13
Asset retirement obligations		3	-	3
Long-term accounts payable and other liabilities		4	-	4
		895	99	994
Total liabilities		4,368	97	4,465
Excess of assets over liabilities		1,976	-	1,976
Total liabilities and excess of assets over liabilities		6,344	97	6,441

December 31, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Inter-company demand facility		141	-	141
Accounts receivable		744	-	744
Regulatory assets		9	-	9
Materials and supplies		4	-	4
Deferred income tax assets		8	-	8
Other		7	-	7
		913	-	913
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		4,993	-	4,993
Construction in progress		293	-	293
Future use land, components and spares		39	-	39
		5,325	-	5,325
Other long-term assets:				
Regulatory assets	B	361	70	431
Intangible assetss (net of accumulated amortization)		108	-	108
Goodwill		73	-	73
Deferred debt costs	A	-	11	11
Derivative instruments	C	-	9	9
Other	C	9	(9)	-
		551	81	632
Total assets		6,789	81	6,870
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	D	692	(692)	-
Accounts payable	D	-	49	49
Accrued liabilities	D	-	643	643
Accrued interest		31	-	31
Regulatory liabilities		16	-	16
Long-term debt payable within one year		324	-	324
		1,063	-	1,063
Long-term debt		2,565	-	2,565
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	576	70	646
Deferred income tax liabilities		171	-	171
Environmental liabilities		134	-	134
Regulatory liabilities		105	-	105
Net unamortized debt premiums	A	-	11	11
Asset retirement obligations		3	-	3
Long-term accounts payable and other liabilities		4	-	4
		993	81	1,074
Total liabilities		4,621	81	4,702
Excess of assets over liabilities		2,168	-	2,168
Total liabilities and excess of assets over liabilities		6,789	81	6,870

Notes to the Transitional Adjustments

Under US GAAP, the Distribution Business (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 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”.

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

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Deferred debt costs	11	11
Other long-term liabilities:		
Net unamortized debt premiums	13	11
Long-term debt	(2)	-

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

Under Canadian GAAP, the Distribution Business disclosed, but was not required to recognize, the net unfunded status of post-retirement and post-employment benefit obligations on the Balance Sheets. Under US GAAP, the Distribution Business recognized the unfunded status of post-retirement and post-employment benefit obligations on the 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 post-retirement and post-employment benefit obligations and the associated regulatory assets offset each other, with no material impact on the 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 $22 million on January 1, 2011 and $18 million on December 31, 2011.

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

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Regulatory assets	86	70
Other long-term liabilities:		
Post-retirement and post-employment benefit liability	(86)	(70)

C. Derivative Instruments (classification change)

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

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

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Derivative instruments	1	9
Other	(1)	(9)

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".

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

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Current liabilities:		
Accounts payable	43	49
Accrued liabilities	518	643
Accounts payable and accrued charges	(561)	(692)

23. COMPARATIVE FIGURES

The comparative Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2012 Financial Statements.

Consolidated Financial Statements of

HALDIMAND COUNTY UTILITIES INC.

Year ended December 31, 2013

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Haldimand County Utilities Inc.

We have audited the accompanying consolidated financial statements of Haldimand County Utilities Inc., which comprise the consolidated statement of financial position as at December 31, 2013, the consolidated statements of income, retained earnings, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Haldimand County Utilities as at December 31, 2013, and its consolidated results of operations and its consolidated cash flows for the year then ended in accordance with Canadian generally accepted accounting principles**.**

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada
March 26, 2014

HALDIMAND COUNTY UTILITIES INC.

Consolidated Statement of Financial Position

December 31, 2013, with comparative figures for 2012

	2013	2012
Assets:		
Current assets		
Cash and bank	$ 4,953,977	$ 5,733,889
Unbilled revenue	6,671,961	5,589,542
Accounts receivable	5,812,706	4,546,490
Inventory (note 4)	1,359,899	1,334,139
Income taxes recoverable	-	589,771
Prepaid expenses	427,866	276,994
	19,226,409	18,070,825
Property, plant and equipment (note 6)	51,511,920	45,046,411
Future income taxes	1,567,468	2,021,043
	53,079,388	47,067,454
	$ 72,305,797	$ 65,138,279
Liabilities:		
Current liabilities		
Accounts payable and accrued expenses	$ 10,168,857	$ 9,212,675
Income taxes payable	351,925	-
Current portion of long term liabilities	1,299,601	1,299,602
Current portion of customer deposits	90,815	55,346
	11,911,198	10,567,623
Regulatory liabilities (note 7)	3,156,315	3,524,465
Long term liabilities (note 8)	12,397,936	13,698,310
Total liabilities	27,465,449	27,790,398
Deferred credits		
Contributions in aid of construction	9,012,184	4,143,672
Less: amortization to date	1,130,445	1,007,444
	7,881,739	3,136,228
Shareholder’s equity		
Capital (note 9)	20,289,812	20,289,812
Retained earnings	16,668,797	13,921,841
	36,958,609	34,211,653
	$ 72,305,797	$ 65,138,279

The accompanying notes are an integral part of these consolidated financial statements.

HALDIMAND COUNTY UTILITIES INC.

Consolidated Statement of Income

Year ended December 31, 2013, with comparative figures for 2012

	2013	2012
Service revenue (note 10)	$ 59,299,394	$55,529,808
Cost of power	44,716,344	41,186,580
Gross margin on service revenue	14,583,050	14,343,228
Other operating revenue (note 11)	1,352,078	1,363,978
Regulatory adjustment (note 7)	(1,459,184)	-
	14,475,944	15,707,206
Expenses		
Distribution, operation and maintenance (note 12)	3,842,685	4,390,090
Community relations	69,412	143,208
Billing and collecting	1,405,880	1,870,179
General administration	2,059,288	1,946,605
Directors	162,732	120,210
	7,539,997	8,470,292
Amortization	2,251,721	4,100,939
Less: amortization of contributions in aid of construction	123,001	161,264
	2,128,720	3,939,675
	9,668,717	12,409,967
Income before undernoted items	4,807,227	3,297,239
Interest expense	626,133	535,593
Income before income taxes and regulatory adjustment	4,181,094	2,761,646
Income taxes - current (note 13)	890,259	532,237
- future	31,330	279,037
	921,589	811,274
Income before regulatory adjustment	3,259,505	1,950,372
Regulatory adjustment - payment in lieu of taxes	-	1,724,427
- future	-	(524,267)
Net regulatory adjustment	-	1,200,160
Net income	$ 3,259,505	$ 750,212

The accompanying notes are an integral part of these consolidated financial statements

HALDIMAND COUNTY UTILITIES INC.

Consolidated Statement of Retained Earnings

Year ended December 31, 2013, with comparative figures for 2012

	2013	2012
Retained earnings – beginning of year:		
As previously stated	$13,921,841	14,694,980
Adjustment (note 3)	-	(912,022)
	13,921,841	13,782,958
Net income	3,259,505	750,212
Dividends	(512,549)	(611,329)
Retained earnings – end of year	$16,668,797	$13,921,841

The accompanying notes are an integral part of these consolidated financial statements

HALDIMAND COUNTY UTILITIES INC.
Consolidated Statement of Cash Flows

December 31, 2013 with comparative figures for 2012

	2013	2012
Cash flows from operating activities:		
Net income	$ 3,259,505	$ 850,036
Charges (credits) to income not involving cash		
Amortization	2,251,721	4,103,011
Amortization of contributions in aid of capital	(123,001)	(161,264)
(Gain) loss on disposal of property, plant and equipment	(13,492)	(112,536)
Future income taxes	31,327	(345,054)
	5,406,060	4,334,193
Net change in non-cash working capital balances related to operations	(627,389)	20,665
	4,778,671	4,354,858
Cash flows from financing activities:		
Dividends	(512,549)	(611,329)
Deposits from customers, retailers and contractors (net)	34,696	71,031
Contributions in aid of construction	4,868,512	190,388
Long term debt	(1,299,602)	2,572,407
Regulatory liabilities	-	2,106,320
	3,091,057	4,328,817
Cash flows from investing activities:		
Purchase of property, plant and equipment	(9,204,653)	(9,345,962)
Proceeds on disposal of property, plant and equipment	500,915	119,585
Regulatory assets	54,098	2,284,829
	(8,649,640)	(6,941,548)
Net increase (decrease) in cash and bank	(779,912)	1,742,127
Cash and bank, beginning of year	5,733,889	3,991,762
Cash and bank, end of year	$ 4,953,977	$ 5,733,889
Supplemental cash flow information:		
Income taxes recovered	$ (588,086)	$ -
Income taxes paid	517,901	1,081,552
Decrease in future taxes resulting from decrease in regulatory liabilities	422,248	-
Interest paid	579,468	485,725

The accompanying notes are an integral part of these consolidated financial statements.

1. Nature of activities:

Haldimand County Utilities Inc. (“the Company”) was incorporated under the Ontario Business Corporations Act on October 13, 2000. The Company acts as the holding company for the shares of Haldimand County Hydro Inc., Haldimand County Energy Inc., and Haldimand County Generation Inc.

2. Significant accounting policies:

The Company has adopted accounting policies prescribed by the Chartered Professional Accountants of Canada (“CPA”) and therefore the financial statements are prepared in accordance with Part V of the CPA Canada Handbook and the policies set forth in the Accounting Procedures Handbook issued by the Ontario Energy Board ("OEB"). The Company has elected to defer its implementation of International Financial Reporting Standards to 2015. Significant accounting policies are as follows:

(a) Basis of consolidation:

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries: Haldimand County Hydro Inc., Haldimand County Energy Inc., and Haldimand County Generation Inc.

(b) Measurement uncertainty:

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures thereto. Due to inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

Accounts receivable, regulatory assets and liabilities are stated after evaluation of amounts expected to be collected and an appropriate allowance for recoverability. Inventory is recorded net of provisions for obsolescence. Amounts recorded for amortization of capital assets are based on estimates of useful service life.

(c) Inventory:

Inventory is stated at the lower cost or net realizable value and consists of maintenance materials and supplies. Cost is determined on a weighted average basis.

2. Significant accounting policies (continued):

(d) Property, plant and equipment and amortization:

Property, plant and equipment are recorded at their historical cost. Amortization is calculated on a straight-line basis over the estimated useful service life as follows:

Buildings	50 years
Distribution stations	45 years
Distribution lines– overhead	45-60 years
Distribution lines– underground	30-50 years
Distribution transformers	35-60 years
Distribution meters	15-25 years
Sentinel lights	10 years
Rolling stock	8-20 years
Other capital assets	5 – 50 years

Construction in progress assets are not amortized until the projects are complete and in service.

Effective January 1, 2013, as required by the OEB, the Company revised the estimated useful lives of certain distribution assets to reflect the useful lives of the assets in service. The impact of this change is a reduction of the amortization expense by $1,459,184 for the year ended December 31, 2013. This change was adopted prospectively in 2013 as prescribed by the OEB.

(e) Contributions in aid of construction:

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as miscellaneous paid-in capital.

(f) Paid in capital:

Paid in capital arises from development charges received prior to January 1, 2000 which were provided or paid for by developers, and are recorded as a permanent component of shareholder's equity.

(g) Revenue recognition:

Distribution revenues are based on OEB approved distribution rates and are recognized as electricity is delivered to customers and collection is reasonably assured. Distribution revenue includes an estimate of revenue based on electricity delivered but not yet invoiced to customers from the last meter reading date to the end of the year. Incentive payments to which the Company is entitled from the OPA are recognized in revenue in the period when they are determined by the OPA and the amount is communicated to the Company. Other revenue is recognized when earned.

2. Significant accounting policies (continued):

(h) Impairment of long-lived assets:

Generally accepted accounting principles require that an impairment loss be recognized when events or circumstances indicate that the carrying amount of the long-lived asset is not recoverable and exceeds its fair value. Any resulting impairment loss is recorded in the period in which the impairment occurs.

The Company has determined that there was no impairment of long-lived assets as at December 31, 2013.

(i) Payments in lieu of income taxes (PILs):

The Company is currently exempt from taxes under the Income Tax Act (Canada) ("ITA") and the Ontario Corporations Tax Act ("OCTA").

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 1001, the Company was not subject to income or capital taxes.

The Company accounts for payments in lieu of corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

PILs are henceforth referred to as income taxes.

(j) Financial instruments:

Financial instruments are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument. The Company has adopted a policy to classify all financial instruments as follows;

1) Cash and bank are classified as Held for Trading and measured at fair value.

2) Accounts receivable and unbilled revenue are classified as Loans and Receivables and measured at amortized cost using the effective interest rate method.

3) Accounts Payable, amounts due to affiliates and long term liabilities are classified as Other Liabilities and measured at amortized cost.

The Company has adopted the disclosure and presentation requirements of CPA Canada Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

3. Prior period adjustment:

Effective January 1, 2009, Handbook section 3465 Income taxes was amended. The Company did not implement this amendment.

The amendment to Handbook Section 3465 states that where future income taxes may be expected to be included in approved rates charged to customers in the future and to be recovered or returned to future customers, the recognition of a regulatory asset or regulatory liability for the increase or reduction in future revenue is required. Furthermore, the regulatory asset or regulatory liability established by this requirement is a temporary difference for which an additional future income tax asset or liability is recognized. This change has been made on a retroactive basis with a restatement of prior periods presented. As a result of this change, retained earnings as at January 1, 2012 decreased by $912,022, regulatory liabilities increased by $995,898 and future income tax assets increased by 406,299 at December 31, 2012. The impact on the Company's results from operations for the year ended December 31, 2013 was a reduction of future income taxes of $279,862 (2012 - $99,825).

4. Inventory:

The amount of inventories expensed during 2013 were $485,081 (2012 - $626,986).

5. Regulatory environment:

Rate Regulation

The Company is regulated by the OEB, under the authority granted by the Ontario Energy Board Act (1998). The OEB has the power and responsibility to approve or fix rates for the transmission and distribution of electricity, to provide continued rate protection for rural and remote electricity consumers, and to ensure that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

5. Regulatory environment (continued):

Regulatory Accounting

In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non rate-regulated environment. 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 recoverable from customers in the future and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. It also includes regulatory liabilities which represent costs with respect to non-distribution market related charges and variances in recoveries that are expected to be settled in future periods.

Rate Setting:

The distribution rates of the Company are based on a revenue requirement that provides a regulated Maximum Allowable Return on Equity ("MARE") on the amount of the deemed equity component supporting the rate base. The Company files a rate application with the OEB annually. Rates are typically effective May 1 to April 30 of the following year. Accordingly, for the first four months of 2013, distribution revenue is based on the rates approved for 2012. Once every five years, the Company files a Cost of Service application where rates are rebased through a cost-of-service review. In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. A Cost of Service application is based upon a forecast of the annual amount of operating and capital expenses, debt and shareholder's equity required to support the Company's business. An IRM application results in a formulaic adjustment to distribution rates for the annual change in the Gross Domestic Product Implicit price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

The Company's last Cost of Service rate application was filed August 28, 2009 and approved April 26, 2010 for rates effective May 1, 2010. Since that time, the Company has filed annual IRM applications adjusting rates for inflation and productivity and stretch factors as described above. The Company filed a Cost of Service rate application on November 15, 2013 for rates effective May 1, 2014. This application requested a 2% increase in revenue requirement compared to the 2010 application referred to above. The OEB's approval of this application is pending.

The Company also files rate applications periodically to recover or settle its regulatory assets and liabilities.

6. Property, plant and equipment:

	Cost	Accumulated Amortization	2013	2012
Land	$ 127,140	$ -	$ 127,140	$ 127,140
Buildings	2,191,968	519,314	1,672,654	1,722,750
Distribution stations	466,496	193,380	273,116	281,146
Distribution lines–overhead	39,445,593	13,973,468	25,472,125	20,684,410
Distribution lines-underground	10,937,246	4,047,234	6,890,012	5,254,607
Distribution transformers	16,256,394	5,871,375	10,385,019	9,502,284
Distribution meters	5,460,825	1,400,714	4,060,111	4,688,092
Sentinel lights	189,940	169,865	15,075	15,688
Rolling stock	2,417,875	1,272,936	1,144,939	1,024,344
Other capital assets	5,499,146	4,027,417	1,471,729	1,745,950
Total	$ 82,992,623	$ 31,475,703	$ 51,511,920	$ 45,046,411

7. Regulatory assets (liabilities):

	2013	2012
Deferred payments in lieu of taxes	$ 148,070	$ -
Retail settlement variance accounts	(804,111)	(858,095)
Recovery of regulatory asset balances	(517,251)	(1,197,158)
Smart meters	492,146	(4,491)
Low voltage services	(26,343)	(52,744)
Hydro One Networks Inc.	6,256	6,168
Adjustment for change in accounting policy	(1,459,184)	-
Regulatory liability for future taxes	(995,898)	(1,418,145)
	$ (3,156,315)	$ (3,524,465)

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 future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

8. Long-term liabilities:

	2013	2012
Ontario Infrastructure and Lands Corporation (OILC) Interest bearing debentures with semi-annual payments of principal and interest:		
(a) Interest at 2.92%, semi-annual payments of $96,499 plus interest, due April 2015	$ 289,498	$ 482,496
(b) Interest at 3.90%, semi-annual payments of $264,418 plus interest, due April 2020	3,437,437	3,966,273
(c) Interest at 4.39%, semi-annual payments of $133,333 plus interest, due April 2025	3,066,667	3,333,333
(d) Interest at 3.77%, semi-annual payments of $120,521 plus interest, due September 2037	5,785,022	6,026,065
(e) Interest at 2.91%, semi-annual payments of $35,029 plus interest, due September 2022	630,521	700,579
Customer, retailer and contractor deposits	579,207	544,512
	13,788,352	15,053,258
Current portion	1,390,416	1,354,948
Long-term liabilities, end of year	$ 12,397,936	$ 13,698,310

Based upon current repayment terms, the estimated annual principal repayments and return of customer deposits are as follows:

2014	$ 1,390,416
2015	1,281,887
2016	1,161,134
2017	1,165,536
2018	1,209,232
Thereafter	6,189,731

The OILC debentures are secured by a general security agreement on all property owned by the Company.

9. Capital:

	2013	2012
Capital stock		
Authorized – an unlimited number of common shares		
Issued – 3,001 common shares	$ 19,149,049	$ 19,149,049
Miscellaneous paid-in capital	1,140,763	1,140,763
	$ 20,289,812	$ 20,289,812

10. Service revenue:

	2013	2012
Residential	$ 13,453,113	$12,443,691
General	10,248,407	9,150,349
Sentinel and street lighting	22,990	43,585
Embedded distributor	6,338,496	5,443,701
Retailer	7,161,094	6,622,082
Retail transmission and low voltage	5,499,403	5,409,240
Regulatory	1,992,840	2,073,930
Distribution services	14,583,051	14,343,230
	$ 59,299,394	$55,529,808

11. Other operating revenue:

	2013	2012
Late payment charges	$ 71,439	$ 66,213
Retail service charges	24,318	27,137
Sentinel light rental	77,173	78,969
Interest earned	94,389	(13,042)
Pole rentals	83,239	76,396
Change of occupancy charges	75,180	81,660
Collection charges	287,220	253,170
Reconnection charges	25,530	30,240
Profit on sale of material services	26,248	19,646
Water and wastewater billings	441,606	441,008
Gain (loss) on disposal of property, plant and equipment	13,492	112,536
Ontario Power Authority CDM fees	-	25,101
Miscellaneous	118,846	154,277
MicroFIT monthly service charge	13,397	10,665
	$ 1,352,077	$ 1,363,976

12. Distribution, operation and maintenance:

	2013	2012
Distribution station equipment	$ 60,580	$ 67,623
Overhead distribution lines	2,173,423	2,120,168
Underground distribution lines	247,043	342,191
Distribution transformers	319,468	576,537
Distribution meters	325,383	509,933
Distribution supervision and engineering	702,401	756,646
Sentinel light maintenance	14,387	16,992
	$ 3,842,685	$ 4,390,090

13. Income taxes - current:

	2013	2012
The income tax provision was calculated based on taxable income. Taxable income is calculated as follows:		
Income before income taxes	$ 4,181,094	$ 2,761,646
Less regulatory adjustment	-	(1,724,427)
Amortization in excess of capital cost allowance	(1,217,471)	704,088
Net change in regulatory assets	533,538	4,391,149
Regulatory assets capitalized for tax purposes	-	(3,669,190)
(Gain) loss on disposal of assets	(13,492)	(112,536)
Other additions and deductions	4,238	(207,850)
Taxable income	$ 3,487,907	$ 2,142,880
Tax at 25.52% (2012 – 24.84%)	$ 890,259	$ 532,237

14. Related party transactions:

The related party of the Company is its parent Haldimand County (the "County").

Amounts payable to and receivable from related parties are non-interest bearing with no fixed terms of repayment.

	2013	2012
Charges received from the County:		
Haldimand County Hydro Inc.:		
Street lights	$ 127,310	$ 82,520
Other	25,187	20,100
Haldimand County Energy Inc.:		
Water and wastewater billing and collecting fees	441,607	441,008
Total charges received from the County	$ 594,104	$ 543,628
Charges paid to the County:		
Haldimand County Hydro Inc.:		
Property taxes	$ 45,122	$ 45,183
Other	844	1,041
Total charges paid to the County	$ 45,966	$ 46,224

15. Prudential support:

Haldimand County Hydro Inc. is required by the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2013, the Company provided prudential support in the form of bank letters of credit of $1,796,505. The letters of credit are secured by a general security agreement on all property owned by the Company.

16. Capital management:

The Company's objectives when managing capital are to maintain financial stability such that it can continue to provide returns for the shareholder and benefits for other stakeholders. The Company meets its objective for managing capital by management oversight and Board monitoring of total capital.

The Company's total capital as at December 31, consists of:

	2013	2012
Total long-term liabilities	$ 13,788,352	$15,053,258
Less: cash and bank	4,953,977	5,733,889
Net long-term liabilities	8,834,375	9,319,369
Total shareholder's equity	36,958,607	34,211,653
Total capital	$ 45,792,982	$43,531,022

17. Financial instruments:

Management and the Board monitor and respond as necessary to any risks arising from financial instruments.

Fair value

The carrying values of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payable and accrued liabilities approximate their fair values because of the short term maturity of these instruments. The fair value of long-term debt with Ontario Infrastructure and Lands Corporation as at December 31, 2013 is $10,015,717.

Interest rate risk

The Company's exposure to interest rate risk relates to its outstanding debentures (see Note 8).

Credit risk

The Company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers and retailers in accordance with direction provided by the OEB. The Company held deposits of $561,708 (2012 - $504,221) at year end in order to mitigate credit risk.

18. Contingencies:

A claim has been filed against the Company related to stray voltage. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

19. Emerging accounting changes:

(a) Transition to International Financial Reporting Standards ("IFRS"):

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that would have Canadian GAAP converge with IFRS, effective January 1, 2011 which would have required entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved a deferral of adoption of IFRS for qualifying entities with activities subject to rate regulation. Part 1 of the CPA Canada Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2015.

The amendment also requires entities that do not prepare its interim and annual financial statements in accordance with Part 1 of the CPA Canada Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

The Corporation has decided to implement IFRS commencing on January 1, 2015.

(b) Accounting for rate regulated activities under IFRS:

The International Accounting Standards Board ("IASB") has issued IFRS 14 *Regulatory Deferral Accounts* in January 2014. This standard provides specific guidance on accounting for the effects of rate regulation and permits first-time adopters of IFRS to continue using previous GAAP to account for regulatory deferral account balances while the IASB completes its comprehensive project in this area. Adoption of this standard is optional for entities eligible to use it. Deferral account balances and movements in the balances will be required to be presented as separate line items on the face of the financial statements distinguished from assets, liabilities, income and expenses that are recognized in accordance with other IFRS. Extensive disclosures will be required to enable users of the financial statements to understand the features and nature of and risks associated with rate regulation and the effect of rate regulation on the entity's financial position, performance and cash flows.

20. Public liability insurance:

The Company is a named insured of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"), which was created on January 1, 1987. A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other through the same attorney. MEARIE provides general liability insurance to member electric utilities in accordance with the Power Corporation Act of Ontario; subsection 116(2), to a maximum of $24,000,000 per occurrence.

Insurance premiums charged to each municipal electric utility consists of a levy per thousand dollars of service revenue subject to a credit/surcharge based on each electric utility's claims experience.

21. Comparative figures:

Certain of the prior year’s figures, provided for purposes of comparison, have been reclassified to conform with the current year’s presentation.

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2012

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

HALDIMAND COUNTY UTILITIES INC.

For the year ended December 31, 2012

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Haldimand County Utilities Inc.

We have audited the accompanying consolidated financial statements of Haldimand County Utilities Inc., which comprise the consolidated statement of financial position as at December 31, 2012, and the consolidated statements of retained earnings, income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Haldimand County Utilities Inc. as at December 31, 2012, and the consolidated results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

April 3, 2013

CHARTERED ACCOUNTANTS
Licensed Public Accountants

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at December 31	2012	2011
ASSETS		
Current Assets		
Cash and bank	5,733,889	3,991,762
Unbilled revenue	5,589,542	5,422,772
Accounts receivable	4,546,330	3,365,083
OPA conservation program	160	-
Inventory	1,334,139	1,254,484
Income taxes recoverable	589,771	595,251
Prepaid expenses	276,994	270,855
	18,070,825	14,900,207
Property, Plant and Equipment (Note 5)	45,046,411	39,810,509
Regulatory Assets (Note 6)	-	2,284,829
Future Tax Asset	1,614,744	1,269,690
	64,731,980	58,265,235
LIABILITIES		
Current Liabilities		
Accounts payable and accrued expenses	9,212,675	7,760,238
OPA conservation program	-	3,281
Current portion of long term liabilities	1,354,948	1,023,662
	10,567,623	8,787,181
Regulatory Liabilities (Note 6)	2,106,320	-
Long Term Liabilities (Note 7)	13,698,310	11,386,158
	26,372,253	20,173,339
Deferred Credits		
Contributions in aid of construction	4,143,672	3,953,284
Less: Amortization to date	1,007,444	846,180
	3,136,228	3,107,104
SHAREHOLDER'S EQUITY		
Capital (Note 8)	20,289,812	20,289,812
Retained Earnings (Page 3)	14,933,687	14,694,980
	35,223,499	34,984,792
	64,731,980	58,265,235

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2012	2011
Retained Earnings - Beginning of Year	14,694,980	12,966,414
Net income	850,036	2,445,316
Dividends	(611,329)	(716,750)
Retained Earnings - End of Year	14,933,687	14,694,980

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF INCOME

For the year ended December 31	2012	2011
Service Revenue (Note 9)	54,238,770	53,256,430
Cost of Power	39,895,540	40,380,841
Gross Margin on Service Revenue	14,343,230	12,875,589
Other Operating Revenue (Note 10)	1,363,976	1,425,187
	15,707,206	14,300,776
Expenses		
Distribution, operation and maintenance (Note 11)	4,390,090	4,145,265
Community relations	143,208	45,426
Billing and collecting	1,870,179	1,157,346
General administration	1,946,605	1,987,290
Directors	120,210	71,906
	8,470,292	7,407,233
Amortization	4,100,939	3,132,560
Less: Amortization of contributions in aid of construction	161,264	154,826
	3,939,675	2,977,734
	12,409,967	10,384,967
Income Before Undernoted Items	3,297,239	3,915,809
Interest expense	535,593	485,501
Income Before Income Taxes and Regulatory Adjustment	2,761,646	3,430,308
Income taxes - current (Note 12)	532,237	1,074,407
- future	179,213	(89,415)
	711,450	984,992
Income Before Regulatory Adjustment	2,050,196	2,445,316
Regulatory adjustment - payment in lieu of taxes (Note 13)	1,724,427	-
- future	(524,267)	-
Net regulatory adjustment	1,200,160	-
Net Income	850,036	2,445,316

See accompanying notes

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended December 31	2012	2011
Cash Flows from Operating Activities		
Net Income	850,036	2,445,316
Charges (credits) to income not involving cash		
Amortization	4,103,011	3,136,204
Amortization of contributions in aid of capital	(161,264)	(154,826)
(Gain) loss on disposal of property, plant and equipment	(112,536)	(21,350)
Future income taxes	(345,054)	(89,415)
	4,334,193	5,315,929
Net change in non-cash working capital balances related to operations	20,665	(306,193)
	4,354,858	5,009,736
Cash Flows from Financing Activities		
Dividends	(611,329)	(716,750)
Deposits from customers, retailers and contractors (net)	71,031	(216,703)
Contributions in aid of construction	190,388	166,470
Long term debt	2,572,407	1,977,239
Regulatory liabilities	2,106,320	-
	4,328,817	1,210,256
Cash Flows from Investing Activities		
Purchase of property, plant and equipment	(9,345,962)	(5,096,689)
Proceeds on disposal of property, plant and equipment	119,585	32,343
Regulatory assets	2,284,829	291,902
	(6,941,548)	(4,772,444)
Net Increase in Cash and Cash Equivalents	1,742,127	1,447,548
Opening Cash and Cash Equivalents	3,991,762	2,544,214
Closing Cash and Cash Equivalents	5,733,889	3,991,762

See accompanying notes

1. NATURE OF ACTIVITIES

Haldimand County Utilities Inc. ("the Company") was incorporated under the Ontario Business Corporations Act on October 13, 2000. The company acts as the holding company for the shares of Haldimand County Hydro Inc., Haldimand County Energy Inc., and Haldimand County Generation Inc.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

(a) Basis of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries: Haldimand County Hydro Inc., Haldimand County Energy Inc., and Haldimand County Generation Inc.

(b) General

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the Ontario Energy Board (OEB) under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles.

(c) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations.

(d) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined on a weighted average basis.

(e) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at their historical cost. Amortization is calculated on a straight-line basis over the estimated useful service life as follows:

Buildings	50 years	Distribution stations	30 years
Distribution lines - overhead	25 years	Distribution lines - underground	25 years
Distribution transformers	25 years	Distribution meters	25 years
Rolling stock	8 years	Sentinel lights	10 years
Other capital assets	5 - 50 years		

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Contributions in Aid of Construction

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as contributed capital.

(g) Revenue Recognition

Distribution revenues are based on OEB approved distribution rates and are recognized as electricity is delivered to customers and collection is reasonably assured. Distribution revenue includes an estimate of revenue based on electricity delivered but not yet invoiced to customers from the last meter reading date to the year end.

(h) Payments in Lieu of Income Taxes (PILs)

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes.

The Company accounts for payments in lieu of corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

(i) Financial Instruments

Financial instruments are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument. The Company has adopted a policy to classify all financial instruments as follows:

(1) - Cash and bank are classified as Held for Trading and measured at fair value.
(2) - Accounts receivable and unbilled revenue are classified as Loans and Receivables and measured at amortized cost using the effective interest rate method.
(3) - Accounts Payable, amounts due to affiliates and long term liabilities are classified as Other Liabilities and measured at amortized cost.
(4) - Purchases and sales of financial instruments are accounted for at the trade date.
(5) - Transaction costs on financial assets and liabilities are expensed as incurred.

The Company has adopted the disclosure and presentation requirements of CICA Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(j) Regulatory Policies

The Company has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.
2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. EMERGING ACCOUNTING CHANGES

The Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. The Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. This was deferred by two years. In March 2013, the AcSB granted an additional optional two year deferral of the adoption of IFRS for rate regulated entities and as such, IFRS may be adopted for financial statements ending December 31, 2015.

The Company has taken the additional deferrals of its adoption of IFRS. Accordingly the Company has prepared its financial statements in accordance with Part V of the CICA Handbook "Pre-Changeover Accounting Standards" for 2012.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The Company will continue to monitor accounting developments with respect to the adoption of IFRS and how any changes will impact on the Company's reporting under IFRS.

4. RATE SETTING

The rates of the Company's electricity distribution business are subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection are collected by Haldimand County Hydro Inc. and remitted to the IESO. Debt retirement charges are collected and remitted to the Ontario Electricity Financial Corporation. The Company retains the distribution charge on the customer hydro invoices.

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 gives 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 which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 6. Haldimand County Hydro Inc.'s approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective May 1, 2012, were calculated on a 2010 test year rate base and included a rate of return on equity of 9.85%.

5. PROPERTY, PLANT AND EQUIPMENT

PROPERTY, PLANT AND EQUIPMENT	Cost	Accumulated Amortization	2012	2011
Land	127,140	-	127,140	131,280
Buildings	2,190,518	467,768	1,722,750	1,751,767
Distribution stations	466,496	185,350	281,146	298,441
Distribution lines - overhead	34,184,427	13,500,017	20,684,410	19,143,867
Distribution lines - underground	9,068,449	3,813,842	5,254,607	4,454,474
Distribution transformers	15,070,996	5,568,712	9,502,284	9,194,795
Distribution meters	6,758,882	2,070,790	4,688,092	1,935,650
Sentinel lights	182,449	166,761	15,688	16,829
Rolling stock	2,207,645	1,183,301	1,024,344	1,025,817
Other capital assets	5,274,302	3,528,352	1,745,950	1,857,589
	75,531,304	30,484,893	45,046,411	39,810,509

6. REGULATORY ASSETS (LIABILITIES)

	2012	2011
Deferred payments in lieu of taxes	-	1,011,901
Retail settlement variance accounts	(858,095)	(1,806,073)
Recovery of regulatory asset balances	(1,197,158)	(345,351)
Smart meters	(4,491)	3,508,788
Low voltage services	(52,744)	(113,364)
Hydro One Networks Inc.	6,168	6,081
Special purpose charge	-	22,847
	(2,106,320)	2,284,829

The deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

On April 4, 2012, the OEB announced its decision regarding the Company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account (RAR). The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2010.

In 2012, the OEB settled the Deferred payments-in-lieu of taxes regulatory accounts. The OEB adjusted this balance to a liability of $705,925 including interest (see Note 13). The balance owing to customers as at December 31, 2012 is $641,504. This amount is included in the Recovery of regulatory asset balances noted above.

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. As at December 31, 2012, the Company has installed its smart meters and received OEB approval for the disposition of and recovery of costs related to smart meters.

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 future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

7. LONG TERM LIABILITIES	2012	2011
Ontario Infrastructure and Lands Corporation (OILC) Interest bearing debentures with semi annual payments of principal and interest:		
(a) Interest at 2.92%, semi-annual payments of $96,499 plus interest, due April 2015	482,496	675,495
(b) Interest at 3.90%, semi-annual payments of $264,418 plus interest, due April 2020	3,966,273	4,495,109
(c) Interest at 4.39%, semi-annual payments of $133,333 plus interest, due April 2025	3,333,333	3,600,000
(d) Interest at 3.77%, semi-annual payments of $120,521 plus interest, due September 2037	6,026,065	-
(e) Interest at 2.91%, semi-annual payments of $35,029 plus interest, due September 2022	700,579	-
Other		
OILC financing advance, interest payable monthly at OILC advance interest rate calculated monthly	-	3,165,735
Customer, retailer and contractor deposits	544,512	473,481
	15,053,258	12,409,820
Current portion	1,354,948	1,023,662
	13,698,310	11,386,158

Based upon current repayment terms, the estimated annual principal repayments and return of customer deposits are as follows:

2013	-	1,354,948
2014	-	1,342,078
2015	-	1,303,767
2016	-	1,165,852
2017	-	1,176,202

The OILC debentures are secured by a general security agreement on all property owned by the Company.

8. CAPITAL

		2012	2011
Capital Stock			
Authorized	- an unlimited number of common shares		
Issued	- 1,001 common shares	19,149,049	19,149,049
Miscellaneous Paid-in Capital		1,140,763	1,140,763
		20,289,812	20,289,812

9. SERVICE REVENUE

	2012	2011
Residential	12,420,910	11,240,324
General	8,843,891	10,434,535
Street lighting	18,911	160,904
Sentinel lighting	23,493	24,383
Embedded Distributor	5,258,988	5,398,454
Retailer	6,216,878	4,816,833
Retail transmission and low voltage	5,038,539	5,379,871
Regulatory	2,073,930	2,925,537
Distribution services	14,343,230	12,875,589
	54,238,770	53,256,430

10. OTHER OPERATING REVENUE

	2012	2011
Late payment charges	66,213	68,188
Retail service charges	27,137	30,425
Sentinel light rental	78,969	80,880
Interest earned	(13,042)	105,737
Pole rentals	76,396	86,987
Change of occupancy charges	81,660	76,290
Collection charges	253,170	220,830
Reconnection charges	30,240	27,095
Profit on sale of material services	19,646	22,402
Water and sewer billings	441,008	428,999
Gain (loss) on disposal of property, plant and equipment	112,536	21,350
Ontario Power Authority CDM fees	25,101	59,153
Miscellaneous	154,277	144,190
Special purpose charge	-	46,517
MicroFIT monthly service charge	10,665	6,144
	1,363,976	1,425,187

11. DISTRIBUTION, OPERATION AND MAINTENANCE

	2012	2011
Distribution station equipment	67,623	273,608
Overhead distribution lines	2,120,168	2,184,159
Underground distribution lines	342,191	230,768
Distribution transformers	576,537	496,830
Distribution meters	509,933	258,936
Distribution supervision and engineering	756,646	684,298
Sentinel light maintenance	16,992	16,666
	4,390,090	4,145,265

12. INCOME TAXES - CURRENT

The income tax provision was calculated based on taxable income.
Taxable income is calculated as follows:

	2012	2011
Income before income taxes	2,761,646	3,430,308
Less regulatory adjustment	(1,724,427)	-
Amortization in excess of Capital Cost Allowance	704,088	(69,304)
Net change in regulatory assets	4,391,149	291,902
Regulatory assets capitalized for tax purposes	(3,669,190)	258,384
(Gain) Loss on disposal of assets	(112,536)	(21,350)
Other additions and deductions	(207,850)	150,776
Taxable income	2,142,880	4,040,716
Tax at 24.84% (2011 - 26.59%)	532,237	1,074,407

13. OEB DECISION ON CERTAIN REGULATORY ASSETS

The OEB issued its decision and order regarding the disposition of account 1562, Deferred Payments in Lieu of Taxes, on August 30, 2012. The decision set the account balance at a liability of $705,923, including principal and interest. The required adjustment of $1,724,427 has been recorded in the Statement of Income after net income from operations.

14. RELATED PARTY TRANSACTIONS

The Company is wholly owned by The Corporation of Haldimand County. Haldimand County Utilities Inc. owns 100% of Haldimand County Hydro Inc., Haldimand County Energy Inc. and Haldimand County Generation Inc. Transactions between Haldimand County Hydro Inc., Haldimand County Energy Inc., Haldimand County Generation Inc., and Haldimand County Utilities Inc. occur in the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

15. PRUDENTIAL SUPPORT

Haldimand County Hydro Inc. is required, through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2012, the Company provided prudential support in the form of bank letters of credit of $1,796,505. The letters of credit are secured by a general security agreement on all property owned by the Company.

16. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain financial stability such that it can continue to provide returns for the shareholder and benefits for other stakeholders. The Company meets its objectives for managing capital by management oversight and Board monitoring of total capital.

The Company's total capital as at December 31, consists of:

	2012	2011
Total long term liabilities	15,053,258	12,409,820
Less: cash and bank	5,733,889	3,991,762
Net long term liabilities	9,319,369	8,418,058
Total shareholder's equity	35,223,499	34,984,792
Total capital	44,542,868	43,402,850

17. FINANCIAL INSTRUMENTS

Management and the Board monitor and respond as necessary to any risks arising from financial instruments.

Fair Value

The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Interest Rate Risk

The Company's exposure to interest rate risk relates to its outstanding debentures (see Note 7).

Credit Risk

The Company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers and retailers in accordance with direction provided by the OEB. The Company held deposits of $504,221 at year end in order to mitigate credit risk.

18. COMPARATIVE FIGURES

Certain of the prior year's figures, provided for purposes of comparison, have been reclassified to conform with the current year's presentation.

19. CONTINGENCIES

A claim has been filed against the Company related to stray voltage. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

Resolution No.
Date: June 10, 2014

THE CORPORATION OF
HALDIMAND COUNTY

SPECIAL COUNCIL RESOLUTION

☐ Bartlett ☐ Morison ☐ Grice ☐ Dalimonte ☐ Shirton ☐ Boyko ☐ Hewitt

Moved By: Boyko

☐ Bartlett ☐ Morison ☐ Grice ☐ Dalimonte ☐ Shirton ☐ Boyko ☐ Hewitt

Seconded By: Morison

WHEREAS The Corporation of Haldimand County (the "Corporation") is the Shareholder of Haldimand County Utilities Inc. ("HCUI");

AND WHEREAS the Corporation considers the sale of all shares of HCUI to be financially beneficial when a reasonable offer (when compared to the County's current financial situation relative to the Sole Shareholder's Agreement) is received;

AND WHEREAS an offer of purchase from Hydro One Networks Inc. was received and subsequent to financial analysis based on sound financial principles, the offer was deemed to be reasonable that included the following:

- Hydro One will apply to the Ontario Energy Board to reduce the electricity distribution rate for Haldimand County Utilities Inc. customers by 1% and freeze that rate for five years.
- All Haldimand County Utilities Inc. employees will transfer to Hydro One after the sale and continue to have jobs.
- Hydro One will build a new satellite operations centre in Dunnville as it restructures its regional operations. In addition Hydro One will bring approximately 30 jobs to the County as it consolidates operations in the area.
- Hydro One has been a good corporate citizen and will continue to support a wide array of community events and organizations in the County.
- The total value of the deal is $75.0 million. Hydro One will pay Haldimand County approximately $65.2 million net after assuming Haldimand County Utilities Inc.'s existing net debt.

Defeated

(Unanimously ________________)

(____________ , ____________)

Carried

(Unanimously ________________)

(____________ , ____________)

Resolution No.
Date: June 10, 2014

THE CORPORATION OF
HALDIMAND COUNTY
SPECIAL COUNCIL RESOLUTION

☐ Bartlett	☐ Morison	☐ Grice	☐ Dalimonte	☐ Shirton	☐ Boyko	☐ Hewitt

Moved By:

☐ Bartlett	☐ Morison	☐ Grice	☐ Dalimonte	☐ Shirton	☐ Boyko	☐ Hewitt

Seconded By:

- Hydro One will establish an Advisory Committee, including representatives of Council, to monitor and provide input about customer service and other matters. Hydro One has agreed to maintain customer service and reliability standards consistent with Haldimand County Utilities Inc.'s past performance.

AND WHEREAS The Corporation desires to approve the sale of all of the issued and outstanding shares of HCUI (the "Shares") to 1908872 Ontario Inc., a subsidiary Hydro One Inc., (the "Transaction"), substantially on the terms and conditions of the Share Purchase Agreement between the Corporation ("the Vendor"), 1908872 Ontario Inc. ("the Purchaser") and Hydro One Inc. ("the Indemintor");

AND WHEREAS the Transaction is subject to approval by the Ontario Energy Board pursuant to section 86 of the *Ontario Energy Board Act*, 1998, as amended, and the Ontario Energy Board's requirements for Mergers, Acquisitions, Amalgamations and Divestitures in the Ontario Electricity Transmission and Distribution Section ("MAADs") necessitating an application to the Ontario Energy Board (the "MAADs Application");

NOW THEREFORE BE IT RESOLVED THAT

1. The Corporation is authorized to sell the Shares for the consideration and substantially on the terms and conditions of the Share Purchase Agreement;

2. The Corporation authorizes the County Solicitor to prepare and submit the MAADs Application to the Ontario Energy Board;

Defeated	Carried
(Unanimously ______)	(Unanimously ______)
(______ , ______)	(______ , ______)

Resolution No.
Date: June 10, 2014

THE CORPORATION OF
HALDIMAND COUNTY
SPECIAL COUNCIL RESOLUTION

☐ Bartlett	☐ Morison	☐ Grice	☐ Dalimonte	☐ Shirton	☐ Boyko	☐ Hewitt

Moved By:

☐ Bartlett	☐ Morison	☐ Grice	☐ Dalimonte	☐ Shirton	☐ Boyko	☐ Hewitt

Seconded By:

3. The Share Purchase Agreement is approved as containing a correct statement of the terms and conditions on which the sale of the Shares are to be made and of the respective rights and obligations of the Corporation and Hydro One under the Share Purchase Agreement and the Mayor and Clerk are authorized to execute and deliver the Share Purchase Agreement and MAADs Application on behalf of the County, and any additions and amendments to the Share Purchase Agreement as the County Solicitor may approve and deem necessary, the execution and delivery of the Share Purchase Agreement and MAADs Application by the Mayor being conclusive evidence of such approval; and

4. The Mayor and Clerk are authorized and directed to take all such action as may be necessary or advisable to complete the Transaction and/or MAADs Application including, but not limited to, the execution and delivery of such ancillary agreements, documents, letters, certificates, writings and receipts as in the option of the County Solicitor may be necessary or desirable to complete the Transaction and/or MAADs application.

5. A by-law authorizing the Mayor and Clerk to execute the Share Purchase Agreement be presented to Council for enactment.

Defeated

(Unanimously __________)

(______ , ______)

Carried

(Unanimously __________)

(7 , 0)

Residential Bill Impact (Typical Consumption Level)

Rate Class	Residential
Monthly Consumption (kWh)	800
Peak (kW)	0
Loss factor	1.0655
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	852.4
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Acquisition Rate ($)	Proposed Acquisition Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.086	51.60	600	0.086	51.60	0.00	0.00%	37.53%	
Energy Second Tier (kWh)	200	0.101	20.20	200	0.101	20.20	0.00	0.00%	14.69%	
Sub-Total: Energy (RPP)			**71.80**			**71.80**	**0.00**	**0.00%**	**52.23%**	
TOU-Off Peak	512	0.075	38.40	512	0.075	38.40	0.00	0.00%		27.58%
TOU-Mid Peak	144	0.112	16.13	144	0.112	16.13	0.00	0.00%		11.58%
TOU-On Peak	144	0.135	19.44	144	0.135	19.44	0.00	0.00%		13.96%
Sub-Total: Energy (TOU)			**73.97**			**73.97**	0.00	0.00%	**53.80%**	**53.13%**
Service Charge	1	17.01	17.01	1	16.84	16.84	-0.17	-1.00%	12.25%	12.10%
Distribution Volumetric Rate	800	0.0248	19.84	800	0.0246	19.68	-0.16	-0.81%	14.32%	14.14%
Low Voltage Service Rate	800	0.0004	0.32	800	0.0004	0.32	0.00	0.00%	0.23%	0.23%
Sub-Total: Base Distribution (excluding riders and pass through)			**37.17**			**36.84**	**-0.33**	**-0.89%**	**26.80%**	**26.46%**
Fixed Rate Riders	1	0	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Volumetric Rate Riders	800	-0.0006	-0.48	800	-0.0006	-0.48	0.00	0.00%	-0.35%	-0.34%
Sub-Total: Distribution (excluding pass through)			**36.69**			**36.36**	**-0.33**	**-0.90%**	**26.45%**	**26.12%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.57%	0.57%
Line Losses on Cost of Power (based on two-tier RPP prices)	52	0.10	5.29	52	0.10	5.29	0.00	0.00%	3.85%	3.80%
Line Losses on Cost of Power (based on TOU prices)	52	0.09	4.84	52	0.09	4.84	0.00	0.00%	3.52%	3.48%
Sub-Total: Distribution (based on two-tier RPP prices)			**42.77**			**42.44**	**-0.33**	**-0.77%**	**30.87%**	**30.48%**
Sub-Total: Distribution (based on TOU prices)			**42.32**			**41.99**	**-0.33**	**-0.78%**	**30.55%**	**30.16%**
Retail Transmission Rate – Network Service Rate	852	0.0068	5.80	852	0.0068	5.80	0.00	0.00%	4.22%	4.16%
Retail Transmission Rate – Line and Transformation Connection S	852	0.0052	4.43	852	0.0052	4.43	0.00	0.00%	3.22%	3.18%
Sub-Total: Retail Transmission			**10.23**			**10.23**	**0.00**	**0.00%**	**7.44%**	**7.35%**
Sub-Total: Delivery (based on two-tier RPP prices)			**53.00**			**52.67**	**-0.33**	**-0.62%**	**38.31%**	**37.83%**
Sub-Total: Delivery (based on TOU prices)			**52.55**			**52.22**	**-0.33**	**-0.63%**	**37.99%**	**37.51%**
Wholesale Market Service Rate	852	0.0044	3.75	852	0.0044	3.75	0.00	0.00%	2.73%	2.69%
Rural Rate Protection Charge	852	0.0013	1.11	852	0.0013	1.11	0.00	0.00%	0.81%	0.80%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.18%	0.18%
Sub-Total: Regulatory			**5.11**			**5.11**	**0.00**	**0.00%**	**3.72%**	**3.67%**
Debt Retirement Charge (DRC)	800	0.007	**5.60**	800	0.007	**5.60**	**0.00**	**0.00%**	**4.07%**	**4.02%**
Total Bill on Two-Tier RPP (before Taxes)			**135.51**			**135.18**	**-0.33**	**-0.24%**	**98.33%**	
HST		0.13	17.62		0.13	17.57	-0.04	-0.24%	12.78%	
Total Bill (including HST)			**153.13**			**152.75**	**-0.37**	**-0.24%**	**111.11%**	
Ontario Clean Energy Benefit (OCEB)		-0.10	-15.31		-0.10	-15.28	0.04	-0.24%	-11.11%	
Total Bill on Two-Tier RPP (including HSTand OCEB)			**137.81**			**137.48**	**-0.34**	**-0.24%**	**100.00%**	
Total Bill on TOU (before Taxes)			**137.23**			**136.90**	**-0.33**	**-0.24%**		**98.33%**
HST		0.13	17.84		0.13	17.80	-0.04	-0.24%		12.78%
Total Bill (including HST)			**155.07**			**154.70**	**-0.37**	**-0.24%**		**111.11%**
Ontario Clean Energy Benefit (OCEB)		-0.10	-15.51		-0.10	-15.47	0.04	-0.24%		-11.11%
Total Bill on TOU (including HST and OCEB)			**139.56**			**139.23**	**-0.34**	**-0.24%**		**100.00%**

General Service (<50 kW) Bill Impact (Typical Consumption Level)

Rate Class	General Service (<50 kW)
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.0655
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2131
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Acquisition Rate ($)	Proposed Acquisition Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.086	64.50	750	0.086	64.50	0.00	0.00%	19.96%	
Energy Second Tier (kWh)	1,250	0.101	126.25	1,250	0.101	126.25	0.00	0.00%	39.08%	
Sub-Total: Energy (RPP)			**190.75**			**190.75**	**0.00**	**0.00%**	**59.04%**	
TOU-Off Peak	1,280	0.075	96.00	1,280	0.075	96.00	0.00	0.00%		30.38%
TOU-Mid Peak	360	0.112	40.32	360	0.112	40.32	0.00	0.00%		12.76%
TOU-On Peak	360	0.135	48.60	360	0.135	48.60	0.00	0.00%		15.38%
Sub-Total: Energy (TOU)			**184.92**			**184.92**	0.00	0.00%	**57.24%**	**58.52%**
Service Charge	1	26.94	26.94	1	26.67	26.67	-0.27	-1.00%	8.26%	8.44%
Distribution Volumetric Rate	2,000	0.0190	38.00	2,000	0.0188	37.60	-0.40	-1.05%	11.64%	11.90%
Low Voltage Service Rate	2,000	0.0004	0.80	2,000	0.0004	0.80	0.00	0.00%	0.25%	0.25%
Sub-Total: Base Distribution (excluding riders and pass through			**65.74**			**65.07**	**-0.67**	**-1.02%**	**20.14%**	**20.59%**
Fixed Rate Riders	1	0	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Volumetric Rate Riders	2,000	-0.0009	-1.80	2,000	-0.0009	-1.80	0.00	0.00%	-0.56%	-0.57%
Sub-Total: Distribution (excluding pass through			**63.94**			**63.27**	**-0.67**	**-1.05%**	**19.58%**	**20.02%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.24%	0.25%
Line Losses on Cost of Power (based on two-tier RPP prices)	131	0.10	13.23	131	0.10	13.23	0.00	0.00%	4.10%	4.19%
Line Losses on Cost of Power (based on TOU prices)	131	0.09	12.11	131	0.09	12.11	0.00	0.00%	3.75%	3.83%
Sub-Total: Distribution (based on two-tier RPP prices			**77.96**			**77.29**	**-0.67**	**-0.86%**	**23.92%**	**24.46%**
Sub-Total: Distribution (based on TOU prices			**76.84**			**76.17**	**-0.67**	**-0.87%**	**23.58%**	**24.11%**
Retail Transmission Rate – Network Service Rate	2,131	0.0061	13.00	2,131	0.0061	13.00	0.00	0.00%	4.02%	4.11%
Retail Transmission Rate – Line and Transformation Connection S	2,131	0.0048	10.23	2,131	0.0048	10.23	0.00	0.00%	3.17%	3.24%
Sub-Total: Retail Transmission			**23.23**			**23.23**	**0.00**	**0.00%**	**7.19%**	**7.35%**
Sub-Total: Delivery (based on two-tier RPP prices)			**101.19**			**100.52**	**-0.67**	**-0.66%**	**31.11%**	**31.81%**
Sub-Total: Delivery (based on TOU prices)			**100.07**			**99.40**	**-0.67**	**-0.67%**	**30.77%**	**31.46%**
Wholesale Market Service Rate	2,131	0.0044	9.38	2,131	0.0044	9.38	0.00	0.00%	2.90%	2.97%
Rural Rate Protection Charge	2,131	0.0013	2.77	2,131	0.0013	2.77	0.00	0.00%	0.86%	0.88%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**12.40**			**12.40**	**0.00**	**0.00%**	**3.84%**	**3.92%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.33%**	**4.43%**
Total Bill on Two-Tier RPP (before Taxes)			**318.34**			**317.67**	**-0.67**	**-0.21%**	**98.33%**	
HST		0.13	41.38		0.13	41.30	-0.09	-0.21%	12.78%	
Total Bill (including HST)			**359.72**			**358.96**	**-0.76**	**-0.21%**	**111.11%**	
Ontario Clean Energy Benefit (OCEB)		-0.10	-35.97		-0.10	-35.90	0.08	-0.21%	-11.11%	
Total Bill on Two-Tier RPP (including HSTand OCEB			**323.75**			**323.07**	**-0.68**	**-0.21%**	**100.00%**	
Total Bill on TOU (before Taxes)			**311.39**			**310.72**	**-0.67**	**-0.22%**		**98.33%**
HST		0.13	40.48		0.13	40.39	-0.09	-0.22%		12.78%
Total Bill (including HST)			**351.87**			**351.11**	**-0.76**	**-0.22%**		**111.11%**
Ontario Clean Energy Benefit (OCEB)		-0.10	-35.19		-0.10	-35.11	0.08	-0.22%		-11.11%
Total Bill on TOU (including HST and OCEB			**316.68**			**316.00**	**-0.68**	**-0.22%**		**100.00%**

General Service (50 kW to 4,999 kW) Bill Impact (Typical Consumption Level)

Rate Class	General Service (50 kW to 4,999 kW)
Monthly Consumption (kWh)	500,000
Peak (kW)	1000
Loss factor	1.0655
Load factor	60%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	532,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Acquisition Rate ($)	Proposed Acquisition Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	532,750	0.086	45,816.50	532,750	0.086	45,816.50	0.00	0.00%	67.48%
Energy Second Tier (kWh)	0	0.101	0.00	0	0.101	0.00	0.00	0.00%	0.00%
Sub-Total: Energy (RPP)			**45,816.50**			**45,816.50**	**0.00**	**0.00%**	**67.48%**
Service Charge	1	83.61	83.61	1	82.77	82.77	-0.84	-1.00%	0.12%
Distribution Volumetric Rate	1,000	3.9339	3,933.90	1,000	3.8946	3,894.60	-39.30	-1.00%	5.74%
Low Voltage Service Rate	1,000	0.155	155.00	1,000	0.155	155.00	0.00	0.00%	0.23%
Sub-Total: Base Distribution (excluding riders and pass through)			**4,172.51**			**4,132.37**	**-40.14**	**-0.96%**	6.09%
Fixed Rate Riders	1	0	0.00	1	0	0.00	0.00	0.00%	0.00%
Volumetric Rate Riders	1,000	-1.0348	-1,034.80	1,000	-1.0348	-1,034.80	0.00	0.00%	-1.52%
Sub-Total: Distribution			**3,137.71**			**3,097.57**	**-40.14**	**-1.28%**	4.56%
Retail Transmission Rate – Network Service Rate	1,000	2.6016	2,601.60	1,000	2.6016	2,601.60	0.00	0.00%	3.83%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,000	2.0329	2,032.90	1,000	2.0329	2,032.90	0.00	0.00%	2.99%
Sub-Total: Retail Transmission			**4,634.50**			**4,634.50**	**0.00**	**0.00%**	**6.83%**
Sub-Total: Delivery			**7,772.21**			**7,732.07**	**-40.14**	**-0.52%**	**11.39%**
Wholesale Market Service Rate	532,750	0.0044	2,344.10	532,750	0.0044	2,344.10	0.00	0.00%	3.45%
Rural Rate Protection Charge	532,750	0.0013	692.58	532,750	0.0013	692.58	0.00	0.00%	1.02%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**3,036.93**			**3,036.93**	**0.00**	**0.00%**	**4.47%**
Debt Retirement Charge (DRC)	500,000	0.007	**3,500.00**	500,000	0.007	**3,500.00**	**0.00**	**0.00%**	**5.15%**
Total Bill (before Taxes)			**60,125.64**			**60,085.50**	**-40.14**	**-0.07%**	**88.50%**
HST		0.13	7,816.33		0.13	7,811.11	-5.22	-0.07%	11.50%
Total Bill (including HST)			**67,941.97**			**67,896.61**	**-45.36**	**-0.07%**	**100.00%**
Ontario Clean Energy Benefit (OCEB)		0.00	0.00		0.00	0.00	0.00	0.00%	0.00%
Total Bill (including HST and OCEB)			**67,941.97**			**67,896.61**	**-45.36**	**-0.07%**	**100.00%**

Unmetered Scattered Load Bill Impact (Typical Consumption Level)

Rate Class	Unmetered Scattered Load
Monthly Consumption (kWh)	500
Peak (kW)	0
Loss factor	1.0655
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	532.75
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Acquisition Rate ($)	Proposed Acquisition Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	500	0.086	43.00	500	0.086	43.00	0.00	0.00%	53.99%
Energy Second Tier (kWh)	0	0.101	0.00	0	0.101	0.00	0.00	0.00%	0.00%
Sub-Total: Energy (RPP)			**43.00**			**43.00**	**0.00**	**0.00%**	**53.99%**
Service Charge	1	19.51	19.51	1	19.31	19.31	-0.20	-1.03%	24.24%
Distribution Volumetric Rate	500	0.0025	1.25	500	0.0025	1.25	0.00	0.00%	1.57%
Low Voltage Service Rate	500	0.0004	0.20	500	0.0004	0.20	0.00	0.00%	0.25%
Sub-Total: Base Distribution (excluding riders and pass through)			**20.96**			**20.76**	**-0.20**	**-0.95%**	26.06%
Fixed Rate Riders	1	0	0.00	1	0	0.00	0.00	0.00%	0.00%
Volumetric Rate Riders	500	-0.0017	-0.85	500	-0.0017	-0.85	0.00	0.00%	-1.07%
Sub-Total: Distribution (excluding pass through)			**20.11**			**19.91**	**-0.20**	**-0.99%**	**25.00%**
Line Losses on Cost of Power	33	0.09	2.82	33	0.09	2.82	0.00	0.00%	3.54%
Sub-Total: Distribution			**22.93**			**22.73**	**-0.20**	**-0.87%**	28.53%
Retail Transmission Rate – Network Service Rate	533	0.0061	3.25	533	0.0061	3.25	0.00	0.00%	4.08%
Retail Transmission Rate – Line and Transformation Connection Service Rate	533	0.0048	2.56	533	0.0048	2.56	0.00	0.00%	3.21%
Sub-Total: Retail Transmission			**5.81**			**5.81**	**0.00**	**0.00%**	**7.29%**
Sub-Total: Delivery			**28.73**			**28.53**	**-0.20**	**-0.70%**	**35.82%**
Wholesale Market Service Rate	533	0.0044	2.34	533	0.0044	2.34	0.00	0.00%	2.94%
Rural Rate Protection Charge	533	0.0013	0.69	533	0.0013	0.69	0.00	0.00%	0.87%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.31%
Sub-Total: Regulatory			**3.29**			**3.29**	**0.00**	**0.00%**	**4.13%**
Debt Retirement Charge (DRC)	500	0.007	**3.50**	500	0.007	**3.50**	**0.00**	**0.00%**	**4.39%**
Total Bill on Two-Tier RPP (before Taxes)			**78.52**			**78.32**	**-0.20**	**-0.25%**	**98.33%**
HST		0.13	10.21		0.13	10.18	-0.03	-0.25%	12.78%
Total Bill (including HST)			**88.73**			**88.50**	**-0.23**	**-0.25%**	**111.11%**
Ontario Clean Energy Benefit (OCEB)		-0.10	-8.87		-0.10	-8.85	0.02	-0.25%	-11.11%
Total Bill on Two-Tier RPP (including HSTand OCEB)			**79.85**			**79.65**	**-0.20**	**-0.25%**	**100.00%**

Sentinel Lighting Bill Impact (Typical Consumption Level)

Rate Class	Sentinel Lighting
Monthly Consumption (kWh)	77
Peak (kW)	0.21
Loss factor	1.0655
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	82
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Acquisition Rate ($)	Proposed Acquisition Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	77	0.086	6.62	77	0.086	6.62	0.00	0.00%	20.82%
Energy Second Tier (kWh)	0	0.101	0.00	0	0.101	0.00	0.00	0.00%	0.00%
Sub-Total: Energy (RPP)			**6.62**			**6.62**	**0.00**	**0.00%**	**20.82%**
Service Charge	1	14.23	14.23	1	14.09	14.09	-0.14	-0.98%	44.31%
Distribution Volumetric Rate	0.21	36.7261	7.71	0.21	36.3588	7.64	-0.08	-1.00%	24.01%
Low Voltage Service Rate	0.21	0.1099	0.02	0.21	0.1099	0.02	0.00	0.00%	0.07%
Sub-Total: Base Distribution (excluding riders and pass through)			**21.97**			**21.75**	**-0.22**	**-0.99%**	68.39%
Fixed Rate Riders	1	0	0.00	1	0	0.00	0.00	0.00%	0.00%
Volumetric Rate Riders	0.21	2.3763	0.50	0.21	2.3763	0.50	0.00	0.00%	1.57%
Sub-Total: Distribution (excluding pass through)			**22.46**			**22.25**	**-0.22**	**-0.97%**	69.96%
Line Losses on Cost of Power	5	0.09	0.43	5	0.09	0.43	0.00	0.00%	1.36%
Sub-Total: Distribution			**22.90**			**22.68**	**-0.22**	**-0.95%**	**71.32%**
Retail Transmission Rate – Network Service Rate	0.21	1.8886	0.40	0.21	1.8886	0.40	0.00	0.00%	1.25%
Retail Transmission Rate – Line and Transformation Connection S	0.21	1.491	0.31	0.21	1.491	0.31	0.00	0.00%	0.98%
Sub-Total: Retail Transmission			**0.71**			**0.71**	**0.00**	**0.00%**	**2.23%**
Sub-Total: Delivery			**23.61**			**23.39**	**-0.22**	**-0.92%**	**73.55%**
Wholesale Market Service Rate	82	0.0044	0.36	82	0.0044	0.36	0.00	0.00%	1.14%
Rural Rate Protection Charge	82	0.0013	0.11	82	0.0013	0.11	0.00	0.00%	0.34%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.79%
Sub-Total: Regulatory			**0.72**			**0.72**	**0.00**	**0.00%**	**2.26%**
Debt Retirement Charge (DRC)	77	0.007	**0.54**	77	0.007	**0.54**	**0.00**	**0.00%**	**1.69%**
Total Bill on Two-Tier RPP (before Taxes)			**31.49**			**31.27**	**-0.22**	**-0.69%**	**98.33%**
HST		0.13	4.09		0.13	4.07	-0.03	-0.69%	12.78%
Total Bill (including HST)			**35.58**			**35.33**	**-0.25**	**-0.69%**	**111.11%**
Ontario Clean Energy Benefit (OCEB)		-0.10	-3.56		-0.10	-3.53	0.02	-0.69%	-11.11%
Total Bill on Two-Tier RPP (including HSTand OCEB)			**32.02**			**31.80**	**-0.22**	**-0.69%**	**100.00%**

Street Lighting Bill Impact (Typical Consumption Level)

Rate Class	Street Lighting
Monthly Consumption (kWh)	170,000
Peak (kW)	550
Loss factor	1.0655
Load factor	60%
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	181,135
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Acquisition Rate ($)	Proposed Acquisition Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	750	0.086	64.50	750	0.086	64.50	0.00	0.00%	0.12%
Energy Second Tier (kWh)	180,385	0.101	18,218.89	180,385	0.101	18,218.89	0.00	0.00%	34.80%
Sub-Total: Energy (RPP)			**18,283.39**			**18,283.39**	**0.00**	**0.00%**	**34.93%**
Service Charge	2,973	5.7	16,946.10	2,973	5.64	16,767.72	-178.38	-1.05%	32.03%
Distribution Volumetric Rate	550	14.5882	8,023.51	550	14.4423	7,943.27	-80.24	-1.00%	15.17%
Low Voltage Service Rate	550	0.113	62.15	550	0.113	62.15	0.00	0.00%	0.12%
Sub-Total: Base Distribution (excluding riders and pass through)			**25,031.76**			**24,773.14**	**-258.63**	**-1.03%**	47.32%
Fixed Rate Riders	2,973	0	0.00	2,973	0	0.00	0.00	0.00%	0.00%
Volumetric Rate Riders	550	-2.787	-1,532.85	550	-2.787	-1,532.85	0.00	0.00%	-2.93%
Sub-Total: Distribution			**23,498.91**			**23,240.29**	**-258.63**	**-1.10%**	44.40%
Retail Transmission Rate – Network Service Rate	550	1.8791	1,033.51	550	1.8791	1,033.51	0.00	0.00%	1.97%
Retail Transmission Rate – Line and Transformation Connection Service Rate	550	1.4604	803.22	550	1.4604	803.22	0.00	0.00%	1.53%
Sub-Total: Retail Transmission			**1,836.73**			**1,836.73**	**0.00**	**0.00%**	**3.51%**
Sub-Total: Delivery			**25,335.64**			**25,077.01**	**-258.63**	**-1.02%**	**47.90%**
Wholesale Market Service Rate	181,135	0.0044	796.99	181,135	0.0044	796.99	0.00	0.00%	1.52%
Rural Rate Protection Charge	181,135	0.0013	235.48	181,135	0.0013	235.48	0.00	0.00%	0.45%
Standard Supply Service – Administration Charge (if applicable)	2,973	0.25	743.25	2,973	0.25	743.25	0.00	0.00%	1.42%
Sub-Total: Regulatory			**1,775.72**			**1,775.72**	**0.00**	**0.00%**	**3.39%**
Debt Retirement Charge (DRC)	170,000	0.007	**1,190.00**	170,000	0.007	**1,190.00**	**0.00**	**0.00%**	**2.27%**
Total Bill (before Taxes)			**46,584.74**			**46,326.11**	**-258.63**	**-0.56%**	**88.50%**
HST		0.13	6,056.02		0.13	6,022.39	-33.62	-0.56%	11.50%
Total Bill (including HST)			**52,640.76**			**52,348.51**	**-292.25**	**-0.56%**	**100.00%**
Ontario Clean Energy Benefit (OCEB)		0.00	0.00		0.00	0.00	0.00	0.00%	0.00%
Total Bill (including HST and OCEB)			**52,640.76**			**52,348.51**	**-292.25**	**-0.56%**	**100.00%**

Embedded Distributor Bill Impact (Typical Consumption Level)

Rate Class	Embedded Distributor
Monthly Consumption (kWh)	6,055,000
Peak (kW)	18970
Loss factor	1.0288
Load factor	60%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	6,229,384
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Acquisition Rate ($)	Proposed Acquisition Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	6,229,384	0.086	535,727.02	6,229,384	0.086	535,727.02	0.00	0.00%	62.69%
Energy Second Tier (kWh)	0	0.101	0.00	0	0.101	0.00	0.00	0.00%	0.00%
Sub-Total: Energy (RPP)			**535,727.02**			**535,727.02**	**0.00**	**0.00%**	**62.69%**
Service Charge	1	464.17	464.17	1	459.53	459.53	-4.64	-1.00%	0.05%
Distribution Volumetric Rate	18,970	1.4304	27,134.69	18,970	1.4161	26,863.42	-271.27	-1.00%	3.14%
Sub-Total: Base Distribution (excluding riders and pass through)			**27,598.86**			**27,322.95**	**-275.91**	**-1.00%**	3.20%
Fixed Rate Riders	1	0	0.00	1	0	0.00	0.00	0.00%	0.00%
Volumetric Rate Riders	18,970	0.5729	10,867.91	18,970	0.5729	10,867.91	0.00	0.00%	1.27%
Sub-Total: Distribution			**38,466.77**			**38,190.86**	**-275.91**	**-0.72%**	4.47%
Retail Transmission Rate – Network Service Rate	19,516	2.9566	57,702.00	19,516	2.9566	57,702.00	0.00	0.00%	6.75%
Retail Transmission Rate – Line and Transformation Connection Service Rate	19,516	2.3933	46,708.45	19,516	2.3933	46,708.45	0.00	0.00%	5.47%
Sub-Total: Retail Transmission			**104,410.45**			**104,410.45**	**0.00**	**0.00%**	**12.22%**
Sub-Total: Delivery			**142,877.22**			**142,601.31**	**-275.91**	**-0.19%**	**16.69%**
Wholesale Market Service Rate	6,229,384	0.0044	27,409.29	6,229,384	0.0044	27,409.29	0.00	0.00%	3.21%
Rural Rate Protection Charge	6,229,384	0.0013	8,098.20	6,229,384	0.0013	8,098.20	0.00	0.00%	0.95%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**35,507.74**			**35,507.74**	**0.00**	**0.00%**	**4.16%**
Debt Retirement Charge (DRC)	6,055,000	0.007	**42,385.00**	6,055,000	0.007	**42,385.00**	**0.00**	**0.00%**	**4.96%**
Total Bill (before Taxes)			**756,496.98**			**756,221.07**	**-275.91**	**-0.04%**	**88.50%**
HST		0.13	98,344.61		0.13	98,308.74	-35.87	-0.04%	11.50%
Total Bill (including HST)			**854,841.59**			**854,529.81**	**-311.78**	**-0.04%**	**100.00%**
Ontario Clean Energy Benefit (OCEB)		0.00	0.00		0.00	0.00	0.00	0.00%	0.00%
Total Bill (including HST and OCEB)			**854,841.59**			**854,529.81**	**-311.78**	**-0.04%**	**100.00%**

Haldimand County Hydro

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXX X,2015

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. Residential includes Urban, Suburban and Farm customer's premises which can be occupied on a year-round and seasonal basis. Farm applies to properties actively engaged in agricultural production as defined by Statistics Canada. These premises must be supplied from a single phase primary line. The farm definition does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	17.01
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Fixed Acquisition Rate Rider – effective until XX, XXXX	$	(0.17)
Distribution Volumetric Rate	$/kWh	0.0248
Volumetric Acquisition Rate Rider – effective until XX, XXXX	$/kWh	(0.0002)
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Global Adjustment Account (2014) – effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kWh	0.0043
Rate Rider for Disposition of Deferral/Variance Accounts (2014) – effective until April 30, 2015	$/kWh	(0.0014)
Rate Rider for Recovery of Stranded Meter Assets – effective until April 30, 2015	$/kWh	0.0021
Rate Rider for Application of CGAAP Accounting Changes – effective until April 30, 2019	$/kWh	(0.0015)
Funding Adder for Renewable Energy Generation – effective until the next rebasing	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X,2015

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a non-residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	26.94
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Fixed Acquisition Rate Rider – effective until XX, XXXX	$	(0.27)
Distribution Volumetric Rate	$/kWh	0.0190
Volumetric Acquisition Rate Rider – effective until XX, XXXX	$/kWh	(0.0002)
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Global Adjustment Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	0.0043
Rate Rider for Disposition of Deferral/Variance Accounts (2014) – effective until April 30, 2015	$/kWh	(0.0020)
Rate Rider for Recovery of Stranded Meter Assets – effective until April 30, 2015	$/kWh	0.0019
Rate Rider for Application of CGAAP Accounting Changes – effective until April 30, 2019	$/kWh	(0.0010)
Funding Adder for Renewable Energy Generation – effective until the next rebasing	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X,2015

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	83.61
Fixed Acquisition Rate Rider – effective until XX, XXXX	$	(0.84)
Distribution Volumetric Rate	$/kW	3.9339
Volumetric Acquisition Rate Rider – effective until XX, XXXX	$/kW	(0.0393)
Low Voltage Service Rate	$/kW	0.1550
Rate Rider for Disposition of Global Adjustment Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	1.5370
Rate Rider for Disposition of Deferral/Variance Accounts (2014) – effective until April 30, 2015	$/kW	(0.9731)
Rate Rider for Recovery of Stranded Meter Assets – effective until April 30, 2015	$/kW	0.0582
Rate Rider for Application of CGAAP Accounting Changes – effective until April 30, 2019	$/kW	(0.1394)
Funding Adder for Renewable Energy Generation – effective until the next rebasing	$/kW	0.0195
Retail Transmission Rate – Network Service Rate	$/kW	2.6016
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0329

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X,2015

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	19.51
Fixed Acquisition Rate Rider – effective until XX, XXXX	$	(0.20)
Distribution Volumetric Rate	$/kWh	0.0025
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Global Adjustment Account (2014) – effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kWh	0.0043
Rate Rider for Disposition of Deferral/Variance Accounts (2014) – effective until April 30, 2015	$/kWh	(0.0004)
Rate Rider for Application of CGAAP Accounting Changes – effective until April 30, 2019	$/kWh	(0.0015)
Funding Adder for Renewable Energy Generation – effective until the next rebasing	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X,2015

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account that is an unmetered lighting load supplied to a sentinel light. (Metered sentinel lighting is captured under the consumption of the principal service.) The consumption for these customers is assumed to have the same hourly consumption load profile as for Street Lighting. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	14.23
Fixed Acquisition Rate Rider – effective until XX, XXXX	$	(0.14)
Distribution Volumetric Rate	$/kW	36.7261
Volumetric Acquisition Rate Rider – effective until XX, XXXX	$/kW	(0.3673)
Low Voltage Service Rate	$/kW	0.1099
Rate Rider for Disposition of Global Adjustment Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	1.5531
Rate Rider for Disposition of Deferral/Variance Accounts (2014) – effective until April 30, 2015	$/kW	5.9194
Rate Rider for Application of CGAAP Accounting Changes – effective until April 30, 2019	$/kW	(4.1655)
Funding Adder for Renewable Energy Generation – effective until the next rebasing	$/kW	0.6224
Retail Transmission Rate – Network Service Rate	$/kW	1.8886
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4910

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X,2015

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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	5.70
Fixed Acquisition Rate Rider – effective until XX, XXXX	$	(0.06)
Distribution Volumetric Rate	$/kW	14.5882
Volumetric Acquisition Rate Rider – effective until XX, XXXX	$/kW	(0.1459)
Low Voltage Service Rate	$/kW	0.1130
Rate Rider for Disposition of Global Adjustment Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	1.5488
Rate Rider for Disposition of Deferral/Variance Accounts (2014) – effective until April 30, 2015	$/kW	(1.5592)
Rate Rider for Application of CGAAP Accounting Changes – effective until April 30, 2019	$/kW	(1.4430)
Funding Adder for Renewable Energy Generation – effective until the next rebasing	$/kW	0.2152
Retail Transmission Rate – Network Service Rate	$/kW	1.8791
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4604

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X,2015

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION FOR HYDRO ONE NETWORKS INC.

This classification applies to Hydro One Networks Inc., an electricity distributor licensed by the Board, and provided electricity by means of Haldimand County Hydro Inc.'s distribution facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	464.17
Fixed Acquisition Rate Rider - effective until XX, XXXX	$	(4.64)
Distribution Wheeling Service Rate	$/kW	1.4304
Volumetric Acquisition Rate Rider - effective until XX, XXXX	$/kW	(0.0143)
Rate Rider for Disposition of Global Adjustment Account (2014) – effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kW	(0.0465)
Rate Rider for Disposition of Deferral/Variance Accounts (2014) – effective until April 30, 2015	$/kW	0.5729
Retail Transmission Rate – Network Service Rate	$/kW	2.9566
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.3933

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X,2015

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microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.40

Haldimand County Hydro
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X,2015

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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Legal letter charge	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge at meter – during regular hours	$	65.00
Disconnect/Reconnect Charge at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service install & remove – overhead – no transformer	$	500.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Bell Canada Pole Rentals	$	18.08
Norfolk Pole Rentals – Billed	$	28.61

Haldimand County Hydro
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X,2015

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RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

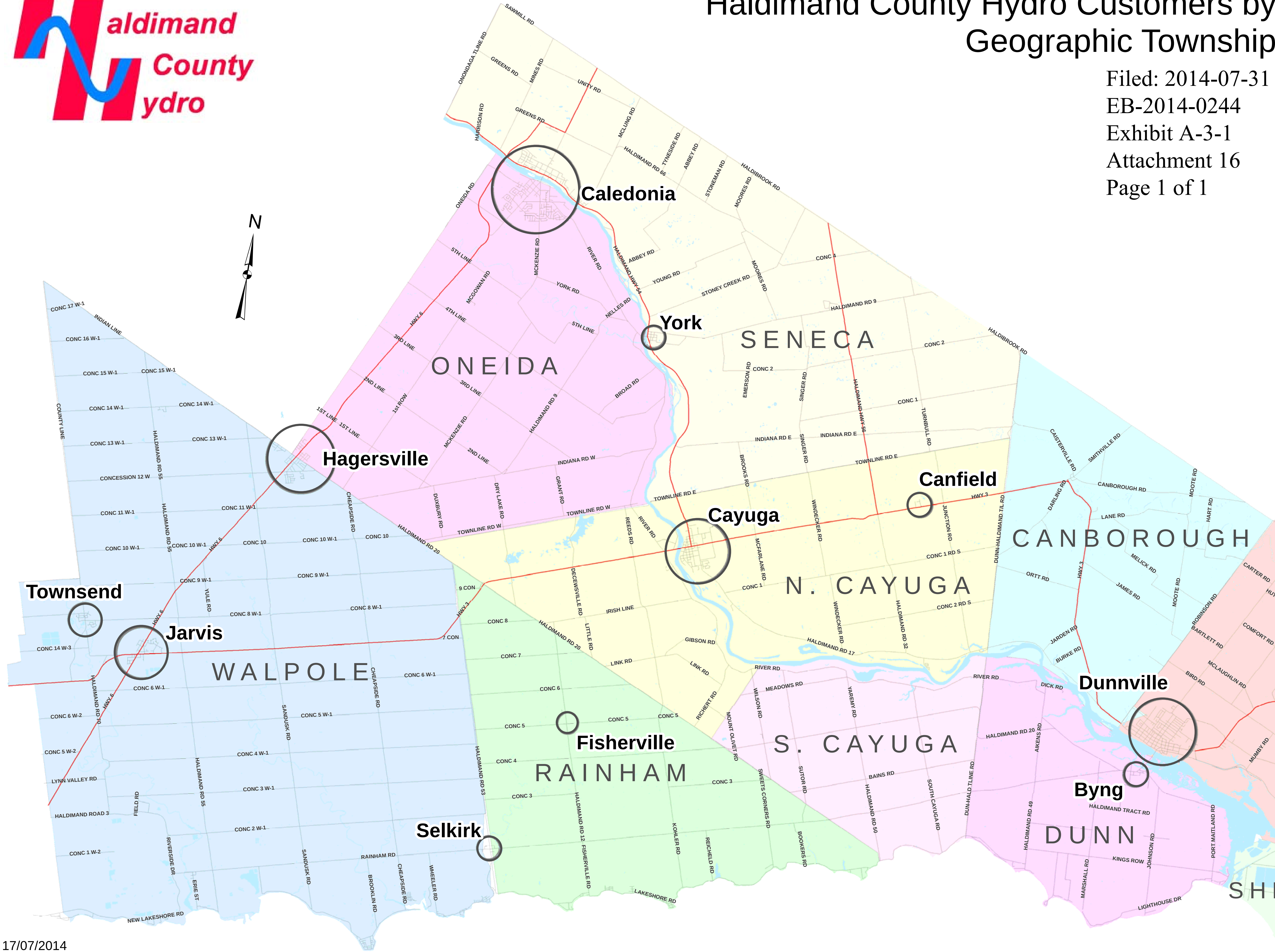
If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0655
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0548
Total Loss Factor – Embedded Distributor – Hydro One Networks Inc.	1.0288

Haldimand County Hydro

Haldimand County Hydro Customers by Geographic Township

Filed: 2014-07-31
EB-2014-0244
Exhibit A-3-1
Attachment 16
Page 1 of 1



Legend

Former Townships

- CANBOROUGH - 620 Customers
- DUNN - 872 Customers
- MOULTON - 1308 Customers
- N. CAYUGA - 1015 Customers
- ONEIDA - 700 Customers
- RAINHAM - 1546 Customers
- S. CAYUGA - 461 Customers
- SENECA - 1210 Customers
- SHERBROOKE - 545 Customers
- WALPOLE - 2401 Customers

High Density Areas

- Byng - 120 Customers
- Caledonia - 3950 Customers
- Canfield - 70 Customers
- Cayuga - 860 Customers
- Dunnville - 2709 Customers
- Fisherville - 130 Customers
- Hagersville - 1457 Customers
- Jarvis - 680 Customers
- Selkirk - 200 Customers
- Townsend - 315 Customers
- York - 95 Customers

17/07/2014