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Oded Hubert
Vice President
Regulatory Affairs

BY COURIER

March 10, 2016

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

Dear Ms. Walli:

EB-2016-0050 – Hydro One Inc's S86 (2)(b) Leave to Purchase Voting Securities of Great Lakes Power Transmission Inc. - Application and Evidence Filing and Request for Confidential Treatment

I am attaching two paper copies of Hydro One Inc's S86 (2)(b) Application for the Leave to Purchase Voting Securities of Great Lakes Power Transmission Inc.

Please note that information has been redacted in Exhibit A, Tab 3, Schedule 1, Attachment 2.

An electronic copy of the redacted version of the application has been submitted electronically while a confidential unredacted version will be sent via courier.

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert

ONTARIO ENERGY BOARD

IN THE MATTER OF an application made pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998* by Hydro One Inc. for leave to purchase all issued and outstanding voting securities of Great Lakes Power Transmission Inc.

APPLICATION

1.0 INTRODUCTION

Hydro One Inc. ("HOI") hereby makes application in accordance with sections 86(2)(b) of the *Ontario Energy Board Act, 1998* for leave allowing HOI to acquire the voting securities of Great Lakes Power Transmission Inc. ("GLPT").

This Application has been prepared in accordance with the filing requirements described in Schedule 2, of the Board's *Handbook to Electricity Distributor and Transmitter Consolidations* dated January 19, 2016 ("Handbook"). Specifically, the Handbook guides transmitters to consider the intent of the Handbook and make appropriate modifications as needed to reflect differences in transmitter consolidations.[1]

In this light, this Exhibit is organized in accordance with Schedule 2 of the Handbook as follows:

- Part 1 provides the Administrative Information
- Part 2 describes the Proposed Transaction
- Part 3 describes the Business of the Transacting Parties

[1] IBID, page 2

- Part 4 describes the Impact of the Proposed Transaction
- Part 5 addresses Rate Considerations
- Part 6 addresses Other Related Matters, and
- Part 7 summarizes the requested relief and includes the signatures of the Applicant.

HOI is a corporation incorporated under the laws of the Province of Ontario and is the parent company of Hydro One Networks Inc. ("Hydro One"). Hydro One is a licensed transmitter regulated by the Ontario Energy Board in accordance with the *Ontario Energy Board Act, 1998* (the "Act").

1937672 Ontario Inc., is a corporation incorporated under the laws of the Province of Ontario and is a wholly owned subsidiary of HOI and will own all of the limited partnership units of Great Lakes Power Transmission Holdings II LP transferred from Brookfield Infrastructure Holdings (Canada) Inc.

GLPT is a corporation incorporated under the laws of the Province of Ontario. GLPT is the general partner of Great Lakes Power Transmission LP ("GLPTLP"). GLPT on behalf of GLPTLP is a licensed transmitter regulated by the Ontario Energy Board (the "Board"). GLPTLP provides transmission services in accordance with the terms and conditions described in Electricity Transmission Licence ET-2007-0649.

The current ownership structure of GLPTLP is shown in **Attachment 1** to this Application.

Brookfield Infrastructure Holdings (Canada) Inc. ("BIH") is a corporation incorporated under the laws of the Province of Ontario. It owns 100% of the limited partnership interests in Great Lakes Power Transmission Holdings II L.P. ("Holdings II LP"), which in turn owns all of the limited partnership units of Great Lakes Power Transmission Holdings L.P.("Holdings LP"). BIH also owns 100% of the common shares of Great Lakes Power Transmission Holdings Inc., ("GLPT

Holdings") which is the general partner of both Holdings II LP and Holdings LP, and 100% of the voting securities of GLPT. In light of this structure, GLPTLP has at all times remained under the control of BIH at the operating and holding level. BIH is a wholly owned indirect subsidiary of Brookfield Infrastructure L.P., the subsidiary holding limited partnership of Brookfield Infrastructure Partners L.P. ("BIP").

2.0 TRANSACTION DESCRIPTION

On January 28, 2016, HOI and its wholly owned subsidiary, 1937672 Ontario Inc., (the "Purchasers") and BIH (the "Vendor") and BIP entered into a purchase agreement, an executed copy of which is found as **Attachment 2** to this Application (the "Agreement"). Under the terms of the Agreement, the Vendor has agreed to sell and the Purchasers have agreed to purchase all of the issued and outstanding voting securities of the licensed transmitter GLPT, the outstanding shares of GLPT Holdings, and the limited partnership units of Holdings II LP (collectively, the "Purchased Securities"). Specifically, the voting securities of the general partners, GLPT Holdings and GLPT will be owned by HOI. 1937672 Ontario Inc. will own all of the limited partnership units of Holdings II LP. The limited partnership units of GLPTLP will continue to be owned by Holdings LP.

A cash payment of $222 million has been agreed to by the parties for the Purchased Securities. The purchase price is subject to adjustment for outstanding debt, deferral accounts and working capital, as discussed in Article 2 of the Agreement.

The terms of the Agreement also contemplate changes being made to the name of GLPT, the licensed transmitter. This will occur within 90 days following the date that the Transaction closes. While the Purchasers have not yet made final decisions regarding the change in name, they expect this determination will be made within 45 days following satisfactory approval of this Application. HOI will notify the Board of the name change and seek applicable licence amendments at that time.

The Agreement also contemplates the Transaction to close on or within 5 business days following receipt of all required approvals. Two significant approvals have been identified: (1) the approvals sought in this Application; and (2) receipt of a *Competition Act* Clearance from the Commissioner of Competition.

All required corporate resolutions made by the transacting parties to approve and cause the transaction to proceed are found as **Attachment 3**.

3.0 DESCRIPTION OF THE BUSINESS OF THE PARTIES TO THE TRANSACTION

3.1 Description of Purchasers and their Electricity Sector Affiliates

Hydro One Inc.

Through control of its subsidiary Hydro One Networks Inc. ("Hydro One"), HOI owns and operates substantially all of Ontario's electricity transmission network, and is the largest electricity distributor in Ontario. HOI has three business segments: (i) Transmission Business; (ii) Distribution Business; and (iii) Other Business.

Transmission Business

The Transmission Business consists of the transmission system owned and operated by Hydro One and a 66% interest in B2M Limited Partnership ("B2M LP"), which is a limited partnership between HOI and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. These interests account for approximately 96% of Ontario's transmission capacity (94.6% Hydro One Transmission, 2.1% B2M LP). HOI's Transmission Business is a rate-regulated business that earns revenues mainly from charging transmission rates that are approved by the OEB. The Transmission Business represents approximately 50% of HOI's total assets as at December 31, 2015, and approximately 50% of its total revenues, net of purchased power, in 2015.

Hydro One's Transmission Business comprises over 29,000 km of transmission lines and 292 transmission stations spanning across Ontario. The high voltage system operates at 500 kV, 230 kV and 115 kV with minor lengths operating at 345 kV and 69 kV. There are approximately 100 generating stations, 47 local distribution companies and 90 end-use transmission customers connected directly to Hydro One's Transmission system, as of the end of December, 2015. In 2015, Hydro One transmitted approximately 137 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Based on assets, Hydro One's transmission system is one of the largest in North America. A map showing the locations of the Hydro One transmission system is found as **Attachment 4**. Hydro One Transmission has an approved rate base of approximately $10 billion.

Distribution Business

HOI's Distribution Business is the largest in Ontario and consists of the distribution system operated by its subsidiaries Hydro One and Hydro One Remote Communities Inc. HOI's Distribution Business is a rate-regulated business that earns revenues mainly by charging distribution rates that must be approved by the OEB. The Distribution Business represented approximately 38% of HOI's total assets as at December 31, 2015, and approximately 49% of its total revenues, net of purchased power, in 2015. The Distribution Business operations will not be affected by this transaction.

Other Business

HOI's Other Business segment consists of the Company's telecommunications business and certain corporate activities. This segment represented approximately 12% of Hydro One's total assets as at December 31, 2015, and approximately 1% of its total revenues, net of purchased power, in 2015. The Transaction will not impact the operations of HOI's Other Business segment.

Copies of the audited 2013 and 2014 financial statements for HOI and Hydro One Networks Inc. (Transmission), and the 2015 Annual Report of Hydro One Limited, the parent company of HOI are found at **Attachment 5** to this Application.

1937672 Ontario Inc.

1937672 Ontario Inc. is a wholly owned subsidiary of HOI. This company will own the limited partnership units of Holdings II LP. In so doing, there is no contemplated transfer or change in the ownership of the limited partnership interests in GLPT or GLPTLP.

3.2 Description of the Vendors and their Electricity Sector Affiliates

Brookfield Infrastructure Partners LP ("BIP")

Brookfield Infrastructure Partners LP ("BIP") is a limited partnership formed under the laws of Bermuda. It owns and operates a variety of high quality, long-life infrastructure assets. Its current operations consist of utility, transport, energy and communications infrastructure businesses in North and South America, Australia and Europe. BIP's mission is to own and operate a globally diversified portfolio of high quality infrastructure assets that will generate sustainable and growing distributions over the long term for its unitholders. At the present time, GLPTLP is BIP's sole investment in Ontario's electricity sector.

Brookfield Infrastructure Holdings (Canada) Inc. ("BIH")

Brookfield Infrastructure Holdings (Canada) Inc. ("BIH") is an indirect wholly owned subsidiary of BIP. BIH owns 100% of the limited partnership interests in Holdings II LP. BIH also owns 100% of the common shares of the two general partners, GLPT Holdings and GLPT.

Great Lakes Power Transmission LP ("GLPTLP")

GLPTLP owns and operates transmission system facilities located on the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario. GLPTLP's transmission assets consist of 15 transmission stations, 560 kilometers of high and medium voltage transmission lines and related infrastructure covering an area of 12,000 square kilometers. A map showing the location of the GLPTLP transmission system facilities is found at **Attachment 6** to this Application.

GLPTLP's OEB approved revenue requirement is approximately 2.6% of the total revenue requirement recovered through the Uniform Transmission Rate ("UTR"). The GLPTLP system provides transmission service to two local distribution companies (Algoma Power and PUC Distribution Inc.), 16 generators and 4 large customers. GLPTLP has an approved 2016 rate base of $218.7M

Copies of the 2013 and 2014 audited financial statements for GLPTLP are found at **Attachment 7** to this Application.

4.0 IMPACT OF THE PROPOSED TRANSACTION

HOI's assessment of the proposed transaction takes into account the Board's "No Harm" Test outlined in the Handbook. Details of this assessment include a discussion of GLPT's operations following the close of the transaction and are described in **Exhibit A, Tab 2, Schedule 1** of this Application. The key conclusions reached in respect of this evidence are as follows:

- Neither Hydro One nor GLPT will seek to increase its future revenue requirements recovered from customers in order to recover transaction costs and premium associated with this transaction.
- The amount of consideration paid by HOI will not have a material impact upon its financial position. The purchase price will be paid in cash and will not be subject to financing and is an amount that is approximately 2% of HOI's fixed assets.

- The adequacy, reliability and quality of service of GLPT's transmission service will not be impacted.
- Longer term synergy savings opportunities are reasonably expected to result in reductions to underlying cost structures. These opportunities to reduce underlying cost structures would not otherwise arise but for the transaction and thus the transaction promotes economic efficiencies and cost effectiveness which benefits customers in the long term.
- While longer term synergy savings opportunities are reasonably expected, reductions to the GLPT cost structure over time are not expected to result in significant reductions to the level of the UTR relative to the UTR rate had the transaction not proceeded. This outcome is due to the relatively small size of the GLPT revenue requirement as compared to the overall revenue requirement recovered through the UTR.

5.0 RATE CONSIDERATIONS

Selection of a Rate Rebasing Deferral Period

HOI has selected a 10 year rate rebasing deferral period commencing on the closing date of the transaction. Should the transaction close before or during the first quarter of 2017, the rate rebasing deferral period would end December 31, 2026. Rates would then be rebased effective January 1, 2027. The rate rebasing deferral period is intended to give HOI the opportunity to realize cost savings through operational integration and the eventual amalgamation with Hydro One. Savings realized during the deferral period will be used by HOI to offset transaction costs and premiums incurred in respect of the transaction. The resulting cost structure reductions following the deferral period will be reflected in rebased rates charged to transmission customers.

It is HOI's understanding that GLPT expects to file in 2016 a rate application for approval of its 2017 and 2018 revenue requirements in 2016. The approved revenue requirements will be used to calculate the UTR established for those years.

Commencing January 1, 2019 and throughout the balance of the deferral period, HOI proposes to calculate GLPT's revenue requirement in the following manner: The approved 2018 GLPT revenue requirement will be adjusted for inflation and this amount will be used as the GLPT 2019 revenue requirement. An annual inflation adjustment would then be applied to each subsequent year during the deferral period. Adoption of this methodology is intended to provide rate certainty to customers while creating a reasonable period of time to allow recovery of transaction costs and premiums.

Earnings Sharing Mechanism

HOI is also proposing to implement an earning sharing mechanism during the last 5 years of the deferral period. The proposed mechanism would share GLPT's earnings on a 50:50 basis where that portion of the achieved return on equity is more than 300 basis points above the ROE approved by the Board for 2018 in GLPT's 2017 and 2018 rate application.

Further details of the proposed rate rebasing deferral period and the earnings sharing mechanism are described in **Exhibit A, Tab 3, Schedule 1** to this Application.

6.0 OTHER RELATED MATTERS

HOI anticipates that recovery of Z-factor and capital factor events (i.e. material costs incurred due to unforeseen events beyond the control of the transmitters) may be applied for in the normal course notwithstanding approval of the deferred rebasing period and the methodology for establishing the GLPT revenue requirement in this period.

GLPT currently reports its financial results on IFRS. Until amalgamation is completed, Hydro One will continue to report the financial results of GLPT under IFRS.

Attachment 2 to this Exhibit contains redactions so that personal information (as defined in the *Freedom of Information and Protection of Privacy Act (Ontario)*) and confidential and commercially sensitive information is not publicly disclosed. Hydro One will provide the Board with an unredacted version of Attachment 2 (marked "confidential") by way of separate filing and in accordance with the Rules and Practice Direction. This filing will delineate the personal information and the commercially sensitive information and provide the reasons for the requested confidential treatment

7.0 SUMMARY OF REQUESTED RELIEF

Based on the foregoing, HOI respectfully requests the following relief:

1. In accordance with section 86(2)(b) of the Act:
    a. Leave to purchase all outstanding voting securities of GLPT.
    b. Acceptance of the proposed rate rebasing deferral period
    c. Acceptance of the proposed earnings sharing mechanism
    d. Acceptance of the proposed methodology to calculate GLPT's 2019 revenue requirement and for each subsequent year during the rate rebasing deferral period

2. Such other relief as may be requested or as the Board may determine to be just and reasonable in these circumstances.

Hydro One Inc. requests that copies of any communications filed in respect of this Application be served on the Applicant and the Applicant's counsel as follows:

a) The Applicant:
Ms. Erin Henderson
Senior Regulatory Co-ordinator
Hydro One Networks Inc.

Mailing Address:	483 Bay Street South Tower, 7th Floor Toronto ON M5G 2P5
Telephone:	(416) 345-4479
Email:	regulatory@hydroone.com

b) Applicant's Counsel:
Gordon M. Nettleton
McCarthy Tétrault

Mailing Address:	4000, 421 – 7th Avenue SW Calgary, AB T2P 4K9
Telephone:	(403) 260-3622
Fax:	(403) 260-3501
Email:	gnettleton@mccarthy.ca

ALL OF WHICH IS RESPECTFULLY SUBMITTED DATED THIS 10th DAY OF MARCH, 2016.

HYDRO ONE INC.

____
Oded Hubert,
Vice President, Regulatory Affairs

Hydro One Inc.
A corporation incorporated under the laws of Ontario
(hereinafter, "Hydro One")

OFFICER'S CERTIFICATE

TO: THE ONTARIO ENERGY BOARD

The undersigned, Oded Hubert, being the Vice President of Hydro One, hereby certifies for and on behalf of Hydro One that:

1. This certificate is given pursuant to the Ontario Energy Board's *Filing Requirements for Consolidation Applications (dated January 19, 2016)*; and

2. The evidence submitted in support of Hydro One Inc.'s Application made pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998* (EB-2016-0050) filed with the Ontario Energy Board is accurate, consistent and complete to the best of my knowledge.

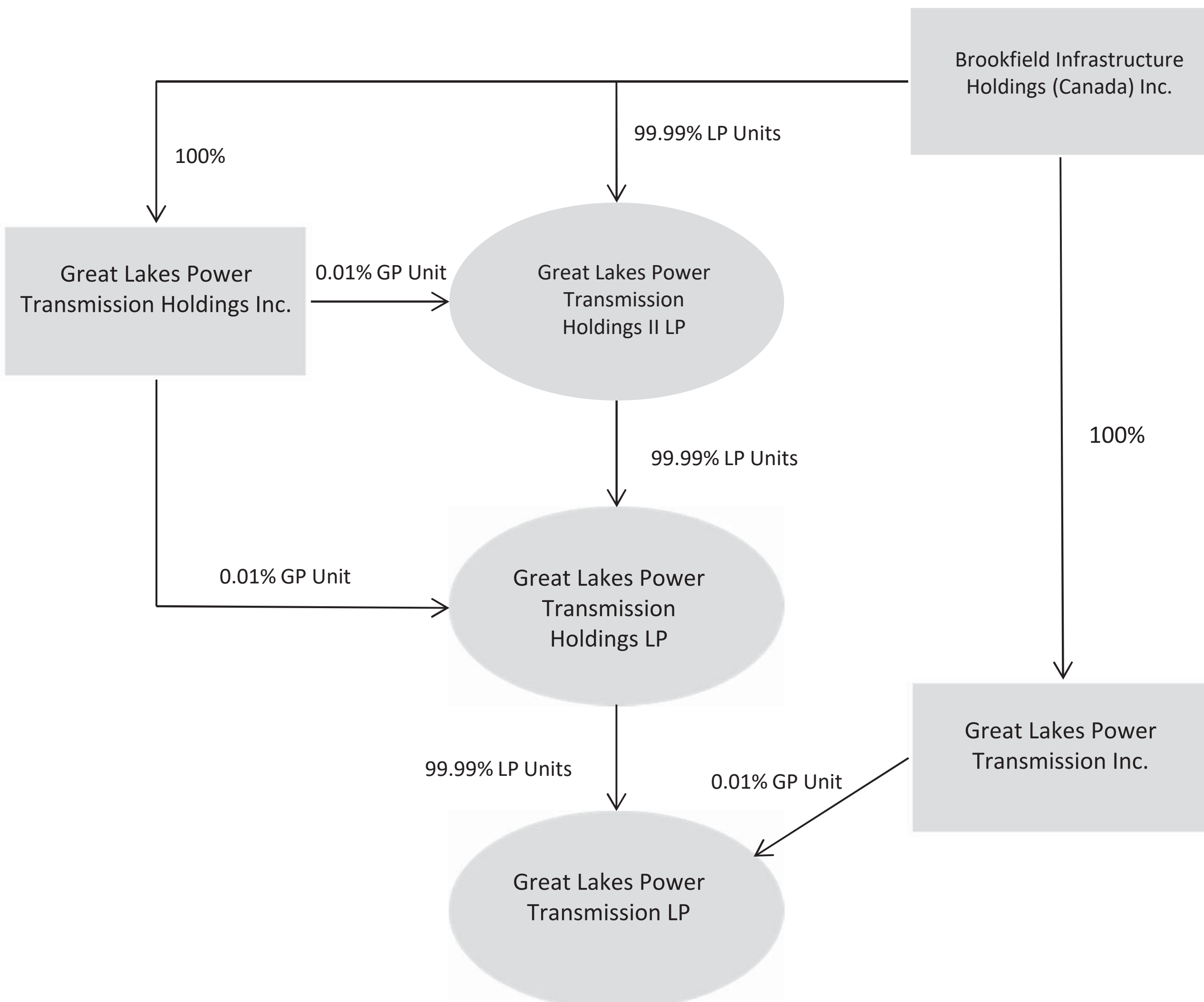
DATED this 10th day of March, 2016.

ORIGINAL SIGNED BY ODED HUBERT

____

Oded Hubert
Vice President, Regulatory Affairs

Great Lakes Power Transmission Limited Partnership
Current Ownership Structure



BROOKFIELD INFRASTRUCTURE HOLDINGS (CANADA) INC.

- and -

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.

- and –

HYDRO ONE INC.

- and -

1937672 ONTARIO INC.

PURCHASE AGREEMENT

January 28, 2016

SCHEDULES

EXHIBITS

PURCHASE AGREEMENT

THIS AGREEMENT is made as of this 28th day of January, 2016,

B E T W E E N:

Brookfield Infrastructure Holdings (Canada) Inc., a corporation incorporated under the laws of the Province of Ontario

(the "**Vendor**")

– and –

Brookfield Infrastructure Partners L.P., a limited partnership formed under the laws of Bermuda

("**BIP**")

– and –

Hydro One Inc., a corporation incorporated under the laws of the Province of Ontario

(the "**Share Purchaser**")

– and –

1937672 Ontario Inc., a corporation incorporated under the laws of the Province of Ontario

(the "**Unit Purchaser**")

RECITALS:

A The Vendor is the registered and beneficial owner of one (1) common share (the "**GLPT GP Share**") of Great Lakes Power Transmission Inc., a company formed under the laws of the Province of Ontario ("**GLPT GP**") representing 100% of the issued and outstanding shares of GLPT GP.

B. The Vendor is the registered and beneficial owner of 100 common shares of Great Lakes Power Transmission Holdings Inc., a company formed under the laws of the Province of Ontario ("**GLPT Holdings GP**"), representing 100% of the issued and outstanding shares of GLPT Holdings GP (the "**GLPT Holdings GP Shares**" and together with the GLPT GP Share, the "**Purchased Shares**").

C. The Vendor is the registered and beneficial owner of 145,984,401 Class A Units of Great Lakes Power Transmission Holdings II LP ("**GLPT Holdings II**", together with GLPT Holdings GP and GLPT GP, the "**Purchased Entities**"), representing all of the outstanding

Class A Units of GLPT Holdings II and representing approximately 99.99% of the issued and outstanding units of GLPT Holdings II (the "**Purchased Units**", and together with the Purchased Shares, the "**Purchased Securities**").

D. GLPT Holdings GP is the registered and beneficial owner of 14,600 Class B Units of GLPT Holdings II, representing all of the outstanding Class B Units of GLPT Holdings II and representing approximately 0.01% of the issued and outstanding units of GLPT Holdings II.

E. The Vendor wishes to sell and transfer to the Purchasers, and the Purchasers wish to purchase from the Vendor, the Purchased Securities, on the terms and subject to the conditions set forth in this Agreement.

NOW THEREFORE in consideration of the mutual covenants and agreements contained in this Agreement and other good and valuable consideration (the receipt and sufficiency of which are hereby acknowledged), the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement and the recitals to this Agreement:

1.1.1 "**Acceptable Owner Test**" has the meaning attributed to such term in Section 6.3.2.

1.1.2 "**Advance Ruling Certificate**" means an advance ruling certificate issued by the Commissioner pursuant to section 102 of the Competition Act in respect of the transactions contemplated by this Agreement.

1.1.3 "**Affiliate**" means, with respect to any Person, any other Person that, directly or indirectly, through one or more intermediaries, Controls or is Controlled by such Person, or is under the common Control of a third Person.

1.1.4 "**Agreement**" means this agreement and all Schedules and Exhibits attached to this agreement, in each case as they may be amended or supplemented from time to time, and the expressions "**hereof**", "**herein**", "**hereto**", "**hereunder**", "**hereby**" and similar expressions refer to this agreement; and unless otherwise indicated, references to Articles, Sections, Schedules and Exhibits are to Articles, Sections, Schedules and Exhibits in this Agreement.

1.1.5 "**Applicable Laws**" means all laws, by-laws, statutes, rules, regulations, principles of law and equity, treaties, orders, rulings, decisions, ordinances, judgments, injunctions, determinations, awards, certificates, decrees, directives, legally enforceable guidelines, standards and policies, and other requirements, whether domestic or foreign, and the terms and conditions of any Permit, in each case of any Governmental Authority.

1.1.6 "**Assets**" means the buildings, plants, structures, furniture, fixtures, machinery, equipment, vehicles and other items of tangible personal property currently owned or leased by the Purchased Entities and the Subsidiaries, together with all other properties and assets of the Purchased Entities and the Subsidiaries.

1.1.7 "**Audited Financial Statements**" means the audited consolidated statements of financial position of GLPT Holdings as at December 31, 2014 and December 31, 2013, the audited consolidated statements of comprehensive income, changes in equity and cash flows for the years ended December 31, 2014 and December 31, 2013, and the accompanying notes thereto, and the report of the auditors of GLPT Holdings thereon, all as attached as Schedule 1.1.7.

1.1.8 "**BIP**" has the meaning attributed to such term in the recitals to this Agreement.

1.1.9 "**Business**" means the business carried on by and on behalf of GLPT consisting of the ownership, operation and maintenance of electricity transmission facilities located in the Algoma district of Ontario, and the transmission of electricity by way of such facilities.

1.1.10 "**Business Day**" means any day, other than Saturday, Sunday or any day on which banking institutions in Toronto, Ontario are not open for business.

1.1.11 "**Charter Documents**" means, as to any Person other than a natural person, the charter, certificate or articles of incorporation, certificate of formation, by-laws, and other organizational documents of such Person, including, with respect to a partnership, any declaration of limited partnership and any partnership agreement, and, with respect to a trust, any declaration of trust or similar document.

1.1.12 "**Claim**" has the meaning attributed to such term in Section 10.3.

1.1.13 "**Closing**" has the meaning attributed to such term in Section 3.1.

1.1.14 "**Closing Date**" means the date on which the Closing occurs.

1.1.15 "**Closing Payment**" has the meaning attributed to such term in Section 2.3.

1.1.16 "**Collective Agreements**" means: (i) the collective agreement by and between GLPT and Power Workers' Union C.U.P.E. Local 1000, as extended by memorandum of agreement dated October 15, 2015; and (ii) any collective agreement established by and between GLPT and Power Workers' Union C.U.P.E. Local 1000 pursuant to the memorandum of agreement between GLPT and Power Workers' Union C.U.P.E. Local 1000 dated November 23, 2015.

1.1.17 "**Commercially Reasonable Efforts**" means efforts which are designed to enable a Party, directly or indirectly, to satisfy a condition to, or to otherwise assist in the consummation of, the transactions contemplated by this Agreement or to assist in the performance of that Party's obligations in this Agreement and which do not require that Party to expend any funds or assume liabilities other than expenditures or liabilities which are reasonable in nature and amount in the context of such transactions or obligations or, where applicable, usual commercial practice.

1.1.18 "**Commissioner**" means the Commissioner of Competition appointed under subsection 7(1) of the Competition Act, and includes a Person duly authorized to exercise the powers and perform the duties of the Commissioner.

1.1.19 "**Competition Act**" means the *Competition Act* (Canada).

1.1.20 "**Competition Act Clearance**" means that:

1.1.20.1 the Commissioner shall have issued an Advance Ruling Certificate; or

1.1.20.2 either: (i) the applicable waiting period under Part IX of the Competition Act in respect of the transactions contemplated by this Agreement shall have expired or shall have been terminated; or (ii) the obligation to give the requisite notice shall have been waived pursuant to paragraph 113(c) of the Competition Act and, in the case of (i) or (ii), the Purchasers have been advised by the Commissioner in writing that he, at that time, does not intend to make an application under section 92 of the Competition Act in respect of the transactions contemplated by this Agreement.

1.1.21 "**Confidentiality Agreement**" has the meaning attributed to such term in Section 9.11.

1.1.22 "**Contest**" has the meaning attributed to such term in Section 10.4.3.1.

1.1.23 "**Contracts**" means any oral or written, legally binding contract or agreement.

1.1.24 "**Control**" means:

1.1.24.1 when applied to the relationship between a Person and a corporation, the beneficial ownership by such Person at the relevant time of shares of such corporation: (i) carrying more than 50% of the voting rights ordinarily exercisable at meetings of shareholders of such corporation, and (ii) representing more than 50% of the equity value of the corporation;

1.1.24.2 when applied to the relationship between a Person and a partnership (other than a limited partnership) or joint venture, (i) the beneficial ownership by such Person at the relevant time of: (a) more than 50% of the voting interests of the partnership or joint venture, and (b) partnership or joint venture interests representing more than 50% of the equity value of the partnership or joint venture, and (ii) it can reasonably be expected that the Person directs the affairs of the partnership or joint venture; or

1.1.24.3 when applied to the relationship between a Person and a limited partnership, the beneficial ownership by such Person at the relevant time of: (i) shares of the general partner or general partners of such limited partnership carrying more than 50% of the voting rights ordinarily exercisable at meetings of shareholders of such general partner or general partners such that it can reasonably be expected that the Person directs the affairs of the limited partnership, and (ii) partnership interests representing more than 50% of the equity value of the limited partnership; and

the term "**Controlled by**" has a corresponding meaning; provided that a Person who Controls a corporation, partnership, limited partnership or joint venture (the "**second mentioned Person**") shall be deemed to Control a corporation, partnership, limited partnership or joint venture which is Controlled by the second-mentioned Person and so on.

1.1.25 "**CRA**" means the Canada Revenue Agency.

1.1.26 "**Current Assets**" has the meaning attributed to such term in Schedule 1.1.26.

1.1.27 "**Current Liabilities**" has the meaning attributed to such term in Schedule 1.1.26.

1.1.28 "**Current Representation**" has the meaning attributed to such term in Section 12.4.

1.1.29 "**Data Room**" means the online electronic data room provided by or on behalf of the Vendor and/or its Affiliates in respect of the transactions contemplated by this Agreement, as it exists on the date of this Agreement.

1.1.30 "**Debt Adjustment Amount**" has the meaning attributed to such term in Section 2.4.1.

1.1.31 "**Direct Claim**" has the meaning attributed to such term in Section 10.3.

1.1.32 "**Easement Documents**" means the easement agreements, substantially in the form set out in Exhibit C, for [redacted].

1.1.33 "**Employee Plans**" means all material plans, agreements or undertakings, whether written or oral, with respect to some or all of the current or former employees of a Purchased Entity or any Subsidiary and pursuant to which a Purchased Entity or any Subsidiary: (i) is a party to or bound by; or (ii) has an obligation to contribute to, relating to retirement savings, pensions, bonuses, profit sharing, deferred compensation, incentive compensation, stock option plans, life or accident insurance, hospitalization, health, medical or dental treatment or expenses, disability, employee loans, vacation policy, severance or termination pay or other similar benefit plans or benefits in respect of the use of any automobiles or other vehicles or equipment, other than a Statutory Plan.

1.1.34 "**Environment**" means the natural environment consisting of ambient air, all layers of the atmosphere, surface water, underground water, soil, subsoil and subsurface strata.

1.1.35 "**Environmental Law**" means all federal, provincial, and municipal statutes, regulations, by-laws, Environmental Permits, orders and rules, relating to the occupational health and safety or the protection or remediation of the Environment.

1.1.36 "**Environmental Permits**" means all Required Permits issued by any Governmental Authority pursuant to an Environmental Law.

1.1.37 "**Estimated Working Capital Adjustment Amount**" has the meaning attributed to such term in Section 2.5.1.

1.1.38 "**Estimated Working Capital**" has the meaning attributed to such term in Section 2.5.1.

1.1.39 "**Estimated Working Capital Statement**" has the meaning attributed to such term in Section 2.5.1.

1.1.40 "**Financial Statements**" means the Audited Financial Statements and the Unaudited Financial Statements.

1.1.41 "**Final Working Capital Adjustment Amount**" has the meaning attributed to such term in Section 2.6.4.

1.1.42 "**Final Working Capital Adjustment Payment Date**" means: (i) if the Vendor has not delivered a Notice of Working Capital Statement Dispute pursuant to Section 2.6.3 with respect to the Final Working Capital Statement, the date that is 30 Business Days after the date the Final Working Capital Statement was delivered to the Vendor by the Purchasers; or (ii) if the Vendor has delivered a Notice of Working Capital Statement Dispute pursuant to Section 2.6.3 with respect to the Final Working Capital Statement, the date that is five Business Days after the date that the Final Working Capital has been agreed between the Parties or determined by the Independent Accounting Firm pursuant to Section 2.6.3.

1.1.43 "**Final Determination**" has the meaning attributed to such term in Section 10.6.3.

1.1.44 "**Final Working Capital**" has the meaning attributed to such term in Section 2.6.2 or Section 2.6.3, as applicable.

1.1.45 "**Final Working Capital Statement**" has the meaning attributed to such term in Section 2.6.1.

1.1.46 "**Fundamental Representations and Warranties**" has the meaning attributed to such term in Section 10.5.4.

1.1.47 "**GLPT**" means Great Lakes Power Transmission LP, a limited partnership formed under the laws of the Province of Ontario.

1.1.48 "**GLPT GP**" has the meaning attributed to such term in the recitals to this Agreement.

1.1.49 "**GLPT GP Share**" has the meaning attributed to such term in the recitals to this Agreement.

1.1.50 "**GLPT Holdings**" means Great Lakes Power Transmission Holdings LP, a limited partnership formed under the laws of the Province of Ontario.

1.1.51 "**GLPT Holdings II**" has the meaning attributed to such term in the recitals to this Agreement.

1.1.52 "**GLPT Holdings GP**" has the meaning attributed to such term in the recitals to this Agreement.

1.1.53 "**GLPT Holdings GP Shares**" has the meaning attributed to such term in the recitals to this Agreement.

1.1.54 "**Governmental Authority**" means any multinational, federal, provincial, state, regional, municipal or local government, any political subdivision thereof or any other governmental, quasi-governmental, judicial, public or statutory instrumentality, authority, body, agency, department, tribunal, bureau or entity, or any arbitrator with authority to bind a Party at law, including the OEB and the IESO.

1.1.55 "**IESO**" means the Province of Ontario's Independent Electricity System Operator and any successor.

1.1.56 "**IFRS**" means International Financial Reporting Standards, as adopted by the International Accounting Standards Board.

1.1.57 "**Indebtedness**" of any Person means, without duplication: (i) all obligations of such Person for borrowed money; (ii) all obligations of such Person evidenced by bonds, debentures, notes or other similar instruments; (iii) all obligations of such Person to pay the deferred purchase price of property, goods or services, except trade accounts payable arising in the ordinary course of business; (iv) all obligations of such Person under leases which are or should be, in accordance with generally accepted accounting principles, consistently applied, recorded as capital leases in respect of which such Person is liable; (v) all deferred obligations of such Person to reimburse any bank or other Person in respect of amounts paid or advanced under a letter of credit or other similar instrument; (vi) all Indebtedness of others secured by a Lien on any asset of such Person, whether or not such Indebtedness is assumed by such Person; and (vii) all Indebtedness of others guaranteed directly or indirectly by such Person or as to which such Person has an obligation substantially the economic equivalent of a guarantee.

1.1.58 "**Indemnified Party**" means a Purchaser Indemnified Party or a Vendor Indemnified Party, as applicable.

1.1.59 "**Indemnitor**" means the Vendor or the Purchasers, as applicable, required to indemnify any Indemnified Party under Article 10.

1.1.60 "**Identified Easements**" means the easements, licenses, rights of occupation and/or use and other rights in real property identified in Schedule 5.13, excluding the Leases.

1.1.61 “**Independent Accountant Dispute Notice**” has the meaning attributed to such term in Section 2.6.3.

1.1.62 “**Independent Accounting Firm**” has the meaning attributed to such term in Section 2.6.3.

1.1.63 “**Indian Band**” means any entity or group falling within the meaning of “band” as that term is defined in the *Indian Act* (Canada).

1.1.64 “**Insurance Policie**s” has the meaning attributed to such term in Section 5.19.

1.1.65 “**Intellectual Property**” means trade-marks and trade-mark applications, trade names, certification marks, patents and patent applications, copyrights, know-how, formulae, processes, inventions, technical expertise, research data, trade secrets, industrial designs and other similar property, whether registered or unregistered, and includes software.

1.1.66 “**Interest Rate**” means the Prime Rate plus 2%, where “**Prime Rate**” means the rate of interest equal to the annual rate of interest quoted by the Canadian Imperial Bank of Commerce, in Toronto, as the reference rate of interest used to determine interest rates chargeable in Canada for demand loans in Canadian dollars to the bank’s most creditworthy commercial customers and which it calls its “prime rate”.

1.1.67 “**Knowledge**” means: (i) with respect to the Vendor, the actual knowledge of Duane Fecteau, Scott Seabrook and Jim Tait, after making all reasonable inquiries; and (ii) with respect to the Purchasers, the actual knowledge of Michael Vels and Joseph Agostino, after making all reasonable inquiries.

1.1.68 “**Labour Representatives**” has the meaning attributed to such term in Section 5.17.1.3.

1.1.69 “**Leases**” means the leases of real property described in Schedule 5.13.

1.1.70 “**Liability**” means any Indebtedness, obligation or other liability of a Person (whether absolute, accrued, contingent, fixed or otherwise, and whether due or to become due).

1.1.71 “**Lien**” means any mortgage, deed of trust, hypothec, lien, claim, pledge, option, charge, security interest, right-of-first refusal, conditional sales agreement or other encumbrance.

1.1.72 “**Loss**” means the amount of: (i) any out-of-pocket loss, cost, expense, damage or Liability (but excluding any contingent Liability until it becomes actual), including interest, fines, penalties, deficiencies and reasonable legal and accounting fees and expenses; less (ii) any amounts received by the relevant Indemnified Parties as a result of any recovery, settlement, or otherwise under or pursuant to any insurance coverage, or pursuant to any claim, recovery, settlement or payment by or against any other Person in connection with the circumstances giving rise to such Loss, including pursuant to an OEB Loss Recovery

Application (provided that the deduction in this clause (ii) shall exclude any cost, deductible and any other amount paid to obtain any such amounts).

1.1.73 "**Material Adverse Effect**" means any changes, effects, events, developments and/or conditions that are, or would reasonably be expected to be, individually or in the aggregate, materially adverse to: (i) the Business, results of operations, condition (financial or otherwise) or assets of the Purchased Entities and the Subsidiaries, taken as a whole; or (ii) the ability of the Vendor to consummate the transactions contemplated hereby; provided, however, that "**Material Adverse Effect**" shall not include any changes, effects, events, developments and/or conditions, directly or indirectly, arising out of or attributable to:

1.1.73.1 any changes, effects, events, developments and/or conditions affecting the Canadian, United States or international financial or securities markets or general economic or political conditions, including changes in the credit, interest rate, commodity (including any increase in the price of raw materials) and/or currency markets or in the availability of financing;

1.1.73.2 any changes in electricity, gas, coal or other fuel supply and transportation markets, including changes in prices for electricity, coal, steam, natural gas or other commodities;

1.1.73.3 any changes in transmission markets or effects of weather or meteorological events;

1.1.73.4 an outbreak or escalation of war (whether or not declared), armed hostilities, acts of terrorism, political instability or other national calamity, crisis or emergency, or any response of any Governmental Authority to any of the foregoing;

1.1.73.5 the execution, announcement or performance of this Agreement or the identity of the Purchasers or the consummation of the transactions contemplated by this Agreement (including any impact or threatened impact on relationships with customers, suppliers, distributors, landlords, employees and/or Governmental Authorities);

1.1.73.6 any change in Applicable Laws (including any enactment, introduction or tabling of any legislation (whether by statute, regulation, order in council or otherwise)) or generally accepted accounting principles or the interpretation thereof applicable to any industry in which any of the Purchased Entities or any of the Subsidiaries operates (and any changes, effects, events, developments or conditions resulting therefrom);

1.1.73.7 any act or omission taken at the request of or with the prior written consent of the Purchasers pursuant to this Agreement; or

1.1.73.8 any changes, effects, events, developments and/or conditions generally affecting the industries in which any of the Purchased Entities or any of the Subsidiaries operates provided, however, that such changes, effects, events, developments and/or conditions do not have a materially disproportionate effect on the Business, results of operations, condition (financial or otherwise) or assets of the Purchased Entities and the Subsidiaries as whole, relative to companies of similar size operating in the industries or markets in which the Purchased Entities and the Subsidiaries operate.

1.1.74 "**Material Contracts**" has the meaning attributed to such term in Section 5.11.1.

1.1.75 "**Notice of Working Capital Statement Dispute**" has the meaning attributed to such term in Section 2.6.3.

1.1.76 "**Note Purchase Agreement**" means the Senior Secured Note Purchase Agreement between GLPT Holdings and [redacted] dated April 9, 2013.

1.1.77 "**OEB**" means the Ontario Energy Board.

1.1.78 "**OEB Act**" means the *Ontario Energy Board Act, 1998*.

1.1.79 "**OEB Approval**" means: (i) an order from the OEB granting leave for the Purchasers to acquire the Purchased Securities pursuant to section 86(2) of the OEB Act; and (ii) if applicable, the OEB has not issued a notice of review pursuant to section 82 of the OEB Act within 60 days of the date that the Purchasers file notice of the transactions contemplated by this Agreement pursuant to section 81 of the OEB Act.

1.1.80 "**OEB Loss Recovery Application**" has the meaning attributed to such term in Section 10.6.2.

1.1.81 "**Outside Date**" means the date that is 12 months following the date of this Agreement, provided that if the Closing has not occurred prior to such date because a Governmental Authority has not delivered, issued or granted a Regulatory Approval, the Outside Date shall be automatically extended by three months upon written notice by either Party to the other Party.

1.1.82 "**Owned Real Property**" has the meaning attributed to such term in Section 5.12.

1.1.83 "**Parties**" means, together, the Purchasers and the Vendor (and to the extent the context requires, BIP, including for purposes of Sections 1.8, 1.9, 1.12, Article 7, Sections 8.1.1, 9.12, 10.10, 10.11 and Article 12) and "**Party**" means any one of them.

1.1.84 "**Permits**" means permits, licences, approvals, consents, authorizations, registrations and certificates, other than any such permits, licences, approvals, consents, authorizations, registrations or certificates issued in respect of the use or occupancy of real property.

1.1.85 "**Permitted Liens**" means:

1.1.85.1 any Lien for Taxes not yet due or being contested in good faith by appropriate proceedings for which adequate reserves have been established in accordance with generally accepted accounting principles, consistently applied;

1.1.85.2 any statutory Lien arising in the ordinary course of business by operation of Applicable Law with respect to a liability that is not yet due or delinquent or being contested in good faith by appropriate proceedings for which adequate reserves have been established in accordance with generally accepted accounting principles, consistently applied;

1.1.85.3 any zoning, use and building by-laws and ordinances and federal, provincial and municipal by-laws and regulations, which do not materially interfere with the use of the property subject to the Lien for the purposes for which it is held;

1.1.85.4 any subdivision, site plan control, development, reciprocal, servicing, facility, facility cost sharing or other agreements currently existing or entered into, which do not materially interfere with the use of the property subject to the Lien for the purposes for which it is held;

1.1.85.5 any encroachments over lands owned by other Persons provided that they: (i) are permitted under agreements with the owners of such lands or have not been objected to by such owners; or (ii) do not materially interfere with the use of the property subject to such encroachments for the purposes for which it is held;

1.1.85.6 encroachments by any buildings, improvements or other facilities which do not materially interfere with the use of the property subject thereto for the purposes for which it is held;

1.1.85.7 permits, licences, approvals, consents, authorizations, registrations, Contracts, leases, servitudes, easements (including heritage easements and Contracts relating thereto), restrictions, restrictive covenants, reciprocal rights, rights-of-way, public ways, rights in the nature of an easement and other similar rights in land granted to or reserved by other Persons (including for sewers, drains, steam, gas and water mains and electric light and power and telephone and telegraph conduits, poles, wires and cables) or which are contemplated or provided for under any subdivision, development, site plan control or similar agreement, and which in the aggregate do not materially interfere with the use thereof for the purposes for which it is held;

1.1.85.8 security given to a public utility or any municipality or other Governmental Authority in the ordinary course of business;

1.1.85.9 pledges or deposits to secure obligations under Applicable Law related to workers' or unemployment compensation or similar legislation or to secure statutory obligations given in the ordinary course of business;

1.1.85.10 statutory reservations, statutory exceptions to title, title defects, irregularities and similar Liens that are of a minor nature and which do not materially impair the use of the property subject to the Lien for the purposes for which it is held;

1.1.85.11 any subsisting reservations, limitations, provisions and conditions contained in any original grants from the Crown of any land or interest therein, reservations of undersurface rights to mines and minerals of any kind;

1.1.85.12 Liens constituting revendication or reclamation rights, purchase-money security interests and similar statutory rights in favour of sellers of goods or other property so long as such Liens only secure the purchase price of such goods or other property and apply only to the goods or other property sold;

1.1.85.13 Liens of contractors, subcontractors, mechanics, workers, suppliers, materialmen, carriers and others in respect of the construction, maintenance, repair or operation of the property subject to the Lien, provided that no claim for lien has been registered in the applicable land registry office or such lien is being contested diligently and in good faith and adequate holdbacks are being maintained as required by Applicable Law or surety bonds have been received in respect of such holdback;

1.1.85.14 statutory Liens or deemed trusts in favour of a Governmental Authority, security indebtedness or obligations not yet due or delinquent which in the aggregate do not materially impair the value or use of the property subject to the Lien for the purposes for which it is held;

1.1.85.15 Liens granted by any Person other than a Purchased Entity or Subsidiary or any of their Affiliates in respect of property owned by such Person;

1.1.85.16 the rights reserved by the grantor of any easement. lease, license, right of occupation or other right to use or occupy property;

1.1.85.17 Liens that, individually or in the aggregate, would not materially impair the use of the property subject to the Lien for the purposes for which it is held; and

1.1.85.18 those Liens as set out in Schedule 1.1.85.

1.1.86 "**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, Governmental Authority or entity however designated or constituted.

1.1.87 "**Post-Closing Representation**" has the meaning attributed to such term in Section 12.4.

1.1.88 "**Pre-Closing Tax Period**" means any Tax period of any Purchased Entity or any Subsidiary ending on or before the Closing Date.

1.1.89 “**Premises**” means all real property owned, leased, or occupied by any Purchased Entity or any Subsidiary in connection with the Business.

1.1.90 “**Proceedings**” has the meaning attributed to such term in Section 4.6.

1.1.91 “**Protected Employees**” has the meaning attributed to such term in Section 9.12.

1.1.92 [redacted]

1.1.93 “**Purchase Price**” has the meaning attributed to such term in Section 2.2.

1.1.94 “**Purchased Entities**” has the meaning attributed to such term in the recitals to this Agreement.

1.1.95 “**Purchased Securities**” has the meaning attributed to such term in the recitals to this Agreement.

1.1.96 “**Purchased Shares**” has the meaning attributed to such term in the recitals to this Agreement.

1.1.97 “**Purchased Units**” has the meaning attributed to such term in the recitals to this Agreement.

1.1.98 “**Purchasers**” means the Share Purchaser and the Unit Purchaser and “**Purchaser**” means either of them.

1.1.99 “**Purchaser Indemnified Party**” means each Purchaser, its respective Affiliates, and each of its and its Affiliates’ respective directors, officers, employees, successors and assigns.

1.1.100 “**Regulatory Approvals**” means the Competition Act Clearance and the OEB Approval.

1.1.101 “**Replacement Letters of Credit**” has the meaning attributed to such term in Section 9.6.1.1.

1.1.102 “**Required Permits**” has the meaning attributed to such term in Section 5.21.

1.1.103 “**Share Purchaser**” has the meaning attributed to such term in the preamble.

1.1.104 “**Statutory Plan**” means a statutory benefit plan pursuant to which a Purchased Entity or a Subsidiary is required to participate in or comply with, including the Canada Pension Plan and plans administered pursuant to applicable health tax, workplace safety, insurance and employment insurance legislation.

1.1.105 “**Straddle Period**” has the meaning attributed to such term in Section 9.4.4.

1.1.106 “**Subsidiaries**” means: (i) GLPT Holdings; (ii) GLPT; (iii) Great Lakes Power Transmission Holding Corp., a corporation incorporated under the laws of the Province of

Ontario; and (iv) 1228185 Ontario Limited, a corporation incorporated under the laws of the Province of Ontario.

1.1.107 "**Substance**" means any substance or material which under any Environmental Law is defined to be "hazardous", "toxic", "deleterious", "caustic", "dangerous", a "contaminant", a "pollutant", a "dangerous good", a "waste", a "source of contamination" or a source of a "pollutant".

1.1.108 "**Target Working Capital Amount**" means $0.00.

1.1.109 "**Tax**" or "**Taxes**" means all federal, state, provincial, local, foreign and other taxes, charges, fees, imposts, levies or other assessments, including all net income, franchise, profits, gross receipts, capital, sales, use, *ad valorem*, value added, transfer, gains, inventory, capital stock, license, withholding, payroll, employment, workers' compensation, social security, unemployment, excise, goods and services, harmonized sales, severance, stamp, occupation, real or personal property, customs duties, fees, assessments and charges of any kind whatsoever, together with any interest and any penalties, fines, additions to tax or additional amounts thereon, imposed by any Governmental Authority and shall include any transferee liability in respect of Taxes.

1.1.110 "**Tax Act**" means the *Income Tax Act* (Canada).

1.1.111 "**Tax Attributes**" means the tax attributes of the Business, the Purchased Entities or the Subsidiaries or any of their assets as reported in any Tax Return filed by the Vendor, the Purchased Entities or the Subsidiaries in respect of any Straddle Period or a taxation year or other period that ended on or prior to the Closing Date.

1.1.112 "**Tax Returns**" means all returns, elections, declarations, designations, reports, estimates, information returns and statements required to be filed in respect of any Taxes, including any schedule or attachment thereto or amendment thereof.

1.1.113 "**Third Party**" has the meaning attributed to such term in Section 10.5.7.

1.1.114 "**Third Party Claim**" has the meaning attributed to such term in Section 10.3.

1.1.115 "**Transfer Taxes**" has the meaning attributed to such term in Section 9.5.

1.1.116 "**Unaudited Financial Statements**" means the unaudited condensed consolidated statement of financial position of GLPT Holdings as at September 30, 2015, the unaudited condensed consolidated statements of changes in equity, comprehensive income and cash flows of GLPT Holdings for the three and nine months ended September 30, 2015 and September 30, 2014, attached as Schedule 1.1.116.

1.1.117 "**Unit Purchaser**" has the meaning attributed to such term in the preamble.

1.1.118 "**Vendor**" has the meaning attributed to such term in the preamble.

1.1.119 "**Vendor Group**" has the meaning attributed to such term in Section 12.4.

1.1.120 "**Vendor Indemnified Parties**" means the Vendor, its Affiliates, and each of its and its Affiliates' respective directors, officers, partners, managers, trustees, members, employees, successors and assigns.

1.1.121 "**Vendor Liability Cap**" means the product of: (i) the Purchase Price; and (ii) 0.20.

1.1.122 "**Vendor Marks**" has the meaning attributed to such term in Section 9.7.

1.1.123 "**Vendor Letters of Credit**" has the meaning attributed to such term in Section 9.6.

1.1.124 "**Waiving Parties**" has the meaning attributed to such term in Section 12.4.

1.1.125 "**Working Capital**" means, at any time, the Current Assets of GLPT Holdings minus the Current Liabilities of GLPT Holdings, in each case as at that time, and as calculated as described in Schedule 1.1.26.

1.1.126 "**Working Capital Statement Dispute**" has the meaning attributed to such term in Section 2.6.3.

1.2 Schedules and Exhibits

The following are the Schedules attached to this Agreement:

Schedule 1.1.7	–	Audited Financial Statements
Schedule 1.1.26	–	Working Capital Adjustment
Schedule 1.1.85	–	Permitted Liens
Schedule 1.1.116	–	Unaudited Financial Statements
Schedule 2.2	–	Deferral Accounts
Schedule 3.2.1.2	–	Resignations
Schedule 5.2	–	Capital of the Purchased Entities and the Subsidiaries
Schedule 5.6	–	No Contravention
Schedule 5.10	–	Non-Arm's Length Transactions
Schedule 5.11	–	Material Contracts
Schedule 5.12	–	Owned Real Property
Schedule 5.13	–	Leases and Identified Easements
Schedule 5.14	–	Environmental Matters
Schedule 5.15	–	Aboriginal Matters
Schedule 5.16	–	Tax Matters
Schedule 5.17	–	Employment Matters
Schedule 5.18	–	Employee Plans

Schedule 5.19	–	Insurance
Schedule 5.21	–	Required Permits
Schedule 5.24	–	Assets
Schedule 9.2	–	Conduct of Business Until Time of Closing
Schedule 9.6	–	Vendor Letters of Credit

The following are the Exhibits attached to this Agreement:

Exhibit A	–	Form of Release to Directors and Officers
Exhibit B	–	Form of Release to the Purchased Entities and Subsidiaries
Exhibit C	–	Forms of Easements

The Parties acknowledge and agree that:

1.2.1 any matter which is disclosed pursuant to any Schedule in such a way as to make reasonably apparent its relevance or applicability to any representation or warranty made elsewhere in this Agreement or to the information called for by any other Schedule shall be deemed to be an exception to such representation or warranty and to be disclosed with respect to such other Schedule, notwithstanding the omission of a reference or cross-reference thereto;

1.2.2 neither the specification of any dollar amount in any representation or warranty nor the inclusion of any item in a Schedule as an exception to a representation or warranty shall be deemed an admission by the Vendor that such item represents an exception or material fact, event or circumstance or that such item is reasonably likely to result in a Material Adverse Effect; and

1.2.3 items included in a Schedule are not necessarily limited to items required by this Agreement, such additional items are set forth for informational purposes only, and the inclusion of such items in a Schedule shall not require the inclusion of other items of a similar nature in the other Schedules.

1.3 Headings and Table of Contents

The inclusion of headings and a table of contents in this Agreement is for convenience of reference only and shall not affect the construction or interpretation hereof.

1.4 Gender and Number

In this Agreement, unless the context otherwise requires, words importing the singular include the plural and vice versa, words importing gender include all genders or the neuter, and words importing the neuter include all genders.

1.5 Currency

Except where otherwise expressly provided, all amounts in this Agreement are stated and shall be paid in Canadian currency.

1.6 Generally Accepted Accounting Principles

In this Agreement, except to the extent otherwise expressly provided, references to "generally accepted accounting principles" mean generally accepted accounting principles in Canada, at the relevant time and applied on a consistent basis, including IFRS.

1.7 Invalidity of Provisions

Each of the provisions contained in this Agreement is distinct and severable and a declaration of invalidity or unenforceability of any such provision or part thereof by a court of competent jurisdiction shall not affect the validity or enforceability of any other provision hereof. To the extent permitted by Applicable Law, the Parties waive any provision of Applicable Law which renders any provision of this Agreement invalid or unenforceable in any respect. The Parties shall engage in good faith negotiations to replace any provision which is declared invalid or unenforceable with a valid and enforceable provision, the economic effect of which comes as close as possible to that of the invalid or unenforceable provision which it replaces.

1.8 Entire Agreement

This Agreement constitutes the entire agreement between the Parties pertaining to the subject matter of this Agreement. There are no warranties, conditions, or representations (including any that may be implied by statute) and there are no agreements in connection with such subject matter except as specifically set forth or referred to in this Agreement. No reliance is placed on any warranty, representation, opinion, advice or assertion of fact made either prior to, contemporaneous with, or after entering into this Agreement, or any amendment or supplement thereto, by either Party to this Agreement or its directors, officers, managers, partners, trustees, employees or agents, to the other Party to this Agreement or its directors, officers, managers, partners, employees, trustees or agents, except to the extent that the same has been reduced to writing and included as a term of this Agreement, and none of the Parties to this Agreement has been induced to enter into this Agreement or any amendment or supplement by reason of any such warranty, representation, opinion, advice or assertion of fact. Accordingly, there shall be no liability, either in tort or in contract, assessed in relation to any such warranty, representation, opinion, advice or assertion of fact, except to the extent contemplated above.

1.9 Waiver, Amendment

Except as expressly provided in this Agreement, no amendment or waiver of this Agreement shall be binding unless executed in writing by the Party to be bound thereby. No waiver of any provision of this Agreement shall constitute a waiver of any other provision nor shall any waiver of any provision of this Agreement constitute a continuing waiver unless otherwise expressly provided.

1.10 Governing Law

This Agreement shall be governed by and construed, interpreted and enforced in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

1.11 Statutes

Any reference in this Agreement to a statute or a statutory provision shall include all by-laws, rules and regulations made from time to time thereunder, and any reference to a statute or to a statutory provision or to a by-law, rule or regulation made thereunder shall be a reference to the statute, statutory provision, by-law, rule or regulation as amended, replaced, extended or re-enacted from time to time.

1.12 Preparation of Agreement

The terms and conditions of this Agreement are the result of negotiations between the Parties and the Parties agree that this Agreement shall not be construed in favour of or against either Party by reason of the extent that either Party or its Affiliates or professional advisors participated in the preparation of this Agreement.

1.13 Miscellaneous

1.13.1 References containing terms such as "includes" and "including", whether or not used with the words "without limitation" or "but not limited to", shall be deemed to not be limited by the specific enumeration of items but shall, in all cases, be deemed to be without limitation and construed and interpreted to mean "includes without limitation" and "including without limitation".

1.13.2 In construing this Agreement, the rule known as the *ejusdem generis* rule shall not apply nor shall any similar rule or approach to the construction of this Agreement and, accordingly, general words introduced or followed by the word "other" or "including" or "in particular" shall not be given a restrictive meaning because they are followed or preceded (as the case may be) by particular examples intended to fall within the meaning of the general words.

1.13.3 Where this Agreement states that an obligation shall be performed "no later than" or "within" or "by" a stipulated date or event which is a prescribed number of days after a stipulated date or event, the latest time for performance shall be 5:00 p.m. on the last day for performance of the obligation concerned, or, if that day is not a Business Day, 5:00 p.m. on the next Business Day.

1.13.4 Where this Agreement states that an obligation shall be performed "on" a stipulated date, the latest time for performance shall be 5:00 p.m. on that day, or, if that day is not a Business Day, 5:00 p.m. on the next Business Day.

1.13.5 Any reference to time of day or date means the local time or date in Toronto, Ontario.

1.13.6 Whenever the terms “will” or “shall” are used in this Agreement they shall be construed and interpreted as synonymous and to read “shall”.

1.13.7 References to any standard, principle, agreement or document include a reference to that standard, principle, agreement or document as amended, supplemented, restated, substituted, replaced, novated or assigned.

ARTICLE 2
PURCHASE AND SALE

2.1 Agreement to Purchase and Sell

Subject to the terms and conditions of this Agreement, at the Closing: (i) the Vendor shall sell and the Unit Purchaser shall purchase the Purchased Units; and (ii) the Vendor shall sell and the Share Purchaser shall purchase the Purchased Shares.

2.2 Purchase Price

2.2.1 The aggregate purchase price payable by the Purchasers to the Vendor for the Purchased Securities shall be equal to:

2.2.1.1 $222,000,000 for the Purchased Securities; plus or minus, as applicable,

2.2.1.2 the Debt Adjustment Amount determined pursuant to Section 2.4; plus

2.2.1.3 the aggregate amount of (i) the expenses reflected in the deferral accounts of GLPT attached as Schedule 2.2; and (ii) any additional expenses incurred by or on behalf of any of the Purchased Entities or the Subsidiaries on or before the Closing Date with the written consent of the Purchasers which have not been recovered in revenue of GLPT before Closing; plus or minus, as applicable,

2.2.1.4 the Estimated Working Capital Adjustment Amount determined pursuant to Section 2.5.1; plus or minus, as applicable,

2.2.1.5 the Final Working Capital Adjustment Amount determined pursuant to Section 2.6.4,

(collectively, the “**Purchase Price**”).

2.2.2 The Parties acknowledge and agree that the Purchase Price shall be allocated as follows:

(i) 0.01% shall be allocated to the GLPT GP Share purchased by the Share Purchaser;

(ii) 0.009999% shall be allocated to the GLPT Holdings GP Shares purchased by the Share Purchaser; and

(iii) 99.980001% shall be allocated to the Purchased Units purchased by the Unit Purchaser.

2.2.3 Except as may be modified pursuant to this Article 2, the Parties shall use the foregoing allocation in the preparation of and filing of all Tax Returns.

2.3 Closing Payment

The amount payable pursuant to Section 2.2.1.1 as adjusted pursuant to Sections 2.2.1.2, 2.2.1.3 and 2.2.1.4 (the "**Closing Payment**") shall be paid in full at the Closing by the Purchasers to the Vendor, in immediately available funds by wire transfer(s) to an account designated by the Vendor not less than two Business Days prior to the Closing Date.

2.4 Debt Adjustment Amount

2.4.1 The "**Debt Adjustment Amount**" shall equal the sum of: (i) the difference between $113,658,965 and the aggregate outstanding principal amount of the Series 1 Senior Bonds of GLPT as of Closing; and (ii) [redacted], and shall be paid in the following manner:

2.4.1.1 if the Debt Adjustment Amount is positive, then the Purchasers shall pay to the Vendor, at the Closing and pursuant to Section 2.2.1.2, an amount equal to the Debt Adjustment Amount; and

2.4.1.2 if the Debt Adjustment Amount is negative, then the absolute value of the Debt Adjustment Amount shall be deducted, pursuant to Section 2.2.1.2, from the Purchase Price otherwise payable to the Vendor at the Closing.

2.5 Estimated Working Capital Adjustment Amount

2.5.1 The Parties acknowledge that it is not possible prior to Closing to conclusively determine the Working Capital as at the Closing Date. Accordingly, no earlier than 10 Business Days and no later than five Business Days before the expected Closing Date, the Vendor shall cause GLPT Holdings to prepare and deliver to the Purchasers a certificate, executed by an officer of GLPT Holdings GP (the "**Estimated Working Capital Statement**"), showing GLPT Holdings' good faith estimate of the Working Capital as at 12:01 a.m. on the Closing Date (the "**Estimated Working Capital**"), which Estimated Working Capital Statement shall be prepared in a manner consistent with the statement of financial position forming part of the Audited Financial Statements. The Estimated Working Capital Statement shall also include a detailed calculation and description of how the Estimated Working Capital was determined, which calculation shall be broken down into its various components. The Vendor shall, and shall cause GLPT Holdings GP to, assist the Purchasers with their review of the Estimated Working Capital Statement prior to Closing.

The "**Estimated Working Capital Adjustment Amount**" shall equal the Estimated Working Capital less the Target Working Capital Amount, and shall be paid in the following manner:

2.5.1.1 if the Estimated Working Capital Adjustment Amount is positive, then the Purchasers shall pay to the Vendor, at the Closing and pursuant to Section 2.2.1.4, an amount equal to the Estimated Working Capital Adjustment Amount; and

2.5.1.2 if the Estimated Working Capital Adjustment Amount is negative, then the absolute value of the Estimated Working Capital Adjustment Amount shall be deducted, pursuant to Section 2.2.1.4, from the Purchase Price otherwise payable to the Vendor at the Closing.

2.6 Final Working Capital Adjustment Amount

2.6.1 As soon as practicable and in any event within 30 days following the Closing Date, the Purchasers shall cause GLPT Holdings to prepare and deliver to the Vendor a certificate, executed by an officer of GLPT Holdings GP (the "**Final Working Capital Statement**") showing the Working Capital as at 12:01 a.m. on the Closing Date, which Final Working Capital Statement shall be prepared in a manner consistent with the statement of financial position forming part of the Audited Financial Statements. The Final Working Capital Statement shall also include a detailed calculation and description of how the Working Capital set out therein was determined, which calculation shall be broken down into its various components.

2.6.2 If the Vendor notifies the Purchasers in writing that it agrees with the Final Working Capital Statement within 30 days after receipt thereof or fails to deliver written notice to the Purchasers of its disagreement therewith within such 30 day period, the Final Working Capital Statement shall be deemed to be conclusive and binding on the Purchasers and the Vendor, the Parties shall be deemed to have agreed thereto, and the "**Final Working Capital**" shall be the amount shown in the Final Working Capital Statement.

2.6.3 If, however, the Vendor notifies the Purchasers in writing of its disagreement with the Final Working Capital Statement within such 30 day period (the "**Notice of Working Capital Statement Dispute**"), then the Purchasers and the Vendor shall attempt, in good faith, to resolve their differences with respect thereto within 15 days after the Purchasers' receipt of the Notice of Working Capital Statement Dispute. If any disagreement over the Final Working Capital Statement (a "**Working Capital Statement Dispute**") is not resolved by the Purchasers and the Vendor within such 15 day period, then the Parties shall appoint a nationally-recognized Canadian public accounting firm that is independent with respect to each of the Parties or, if that firm declines to act as provided hereunder, another firm or independent public accountant as agreed upon by the Vendor and the Purchasers (the "**Independent Accounting Firm**") to resolve the Working Capital Statement Dispute. The Vendor and the Purchasers shall furnish the Independent Accounting Firm with a statement setting forth the items from the Notice of Working Capital Statement Dispute which are still in dispute (the "**Independent Accountant Dispute Notice**"). The Vendor and the Purchasers agree to cooperate with the Independent Accounting Firm and provide it with such information as it reasonably requests to enable it to resolve the Working Capital Statement Dispute. The Vendor and the Purchasers shall be permitted to submit to the Independent Accounting Firm any other material in support of their position with respect to disputed items as long as such material is submitted concurrently to the other Party. Neither the Vendor nor the Purchasers shall meet or speak with the Independent Accounting Firm without the prior consent of the other Party. The Parties shall direct the Independent Accounting Firm, acting as an expert and not as an arbitrator, to, within 30 days from the date that the Independent Accountant Dispute Notice is submitted to the Independent Accounting Firm, make a final determination in respect of the Working Capital Statement Dispute of the appropriate amount of each of the line items in the Final Working Capital Statement as to which there is disagreement as specified in the Independent Accountant Dispute Notice. With respect to each disputed line item, such determination, if not in accordance with the position of either the Vendor or the Purchasers, shall not be in excess of the higher, nor less than the lower, of the amounts advocated by the Vendor in the Notice of Working Capital Statement Dispute or the Purchasers in the Final Working Capital Statement with respect to such disputed line item. For the avoidance of doubt, the Independent Accounting Firm shall not review any line items or make any determination with respect to any matter other than those matters in the Independent Accountant Dispute Notice that are the subject of the Working Capital Statement Dispute. The resolution of the Working Capital Statement Dispute by the Independent Accounting Firm shall be final and binding on the Parties. The fees and expenses of the Independent Accounting Firm, unless otherwise agreed by the Parties, shall be borne as to 50% by the Vendor and as to 50% by the Purchasers. In these circumstances, the "**Final Working Capital**" shall be as agreed between the Parties or as determined by the Independent Accounting Firm pursuant to this Section 2.6.3.

2.6.4 The "**Final Working Capital Adjustment Amount**" shall equal the Final Working Capital less the Estimated Working Capital, and shall be paid in the following manner:

2.6.4.1 if the Final Working Capital Adjustment Amount is positive, then the Purchasers shall pay to the Vendor on the Final Working Capital Adjustment Payment Date an amount equal to the Final Working Capital Adjustment Amount, plus interest thereon at the Interest Rate from the Closing Date to the date of payment, in immediately available funds by wire transfer to an account designated by the Vendor; and

2.6.4.2 if the Final Working Capital Adjustment Amount is negative, then the Vendor shall pay to the Purchasers on the Final Working Capital Adjustment Payment Date an amount equal to the absolute value of the Final Working Capital Adjustment Amount, plus interest thereon at the Interest Rate from the Closing Date to the date of payment, in immediately available funds by wire transfer to an account designated by the Purchasers.

ARTICLE 3
CLOSING

3.1 Location and Time of the Closing

The closing of the purchase and sale of the Purchased Securities (the "**Closing**") shall take place at the offices of Torys LLP at 79 Wellington Street West, Toronto, Ontario commencing at 9:00 a.m. on the day which is five Business Days after the date on which the last of the conditions set forth in Section 8.1 and Section 8.2 (other than any such conditions which by their nature are not capable of being satisfied until the Closing Date) is satisfied or waived, or on such other date and/or at such other time and/or place as the Parties may mutually determine.

3.2 Deliveries at the Closing

3.2.1 At the Closing, the Vendor shall deliver, or cause to be delivered, to the Purchasers the following, each of which: (i) shall be, if applicable, dated as of the Closing Date; and (ii) shall have been, if applicable, duly authorized, executed and delivered as indicated:

3.2.1.1 the certificates referred to in Section 8.1.1 and Section 8.1.2;

3.2.1.2 resignations from those directors and officers of each of the Purchased Entities and Subsidiaries listed on Schedule 3.2.1.2 effective as of the Closing Date;

3.2.1.3 releases from those directors and officers of each of the Purchased Entities and Subsidiaries listed on Schedule 3.2.1.2, excluding Messrs. Fecteau and Seabrook, effective as of the Closing Date, each in the form attached as Exhibit B;

3.2.1.4 the amendment to the partnership agreements of the Purchased Entities and any Subsidiaries, as applicable, as contemplated by Section 9.4.8 of this Agreement; and

3.2.1.5 copies or originals of such other documents, instruments, agreements or certificates necessary or advisable to consummate the transactions contemplated by this Agreement, as the Purchasers may reasonably request.

3.2.2 At the Closing, the Purchasers shall deliver, or cause to be delivered, to the Vendor the following, each of which: (i) shall be, if applicable, dated as of the Closing Date; and (ii) shall have been, if applicable, duly authorized, executed and delivered as indicated:

3.2.2.1 the Closing Payment pursuant to Section 2.3;

3.2.2.2 the Regulatory Approvals;

3.2.2.3 releases from each of the Purchased Entities releasing those individuals listed on Schedule 3.2.1.2, each in the form attached as Exhibit A;

3.2.2.4 the Replacement Letters of Credit and such other documents, instruments, agreements or certificates required pursuant to Section 9.6.2; and

3.2.2.5 copies or originals of such other documents, instruments, agreements or certificates necessary or advisable to consummate the transactions contemplated by this Agreement, as the Vendor may reasonably request.

3.3 Satisfaction of Conditions

Unless otherwise agreed in writing by the Parties, all conditions for the benefit of the Vendor and the Purchasers to proceed with the Closing under this Agreement shall be deemed to have been fully and completely satisfied or waived for all purposes upon completion of the Closing.

ARTICLE 4
REPRESENTATIONS AND WARRANTIES OF THE VENDOR WITH RESPECT TO THE VENDOR

Except as set forth in the Schedules to this Agreement, the Vendor represents and warrants to the Purchasers, and acknowledges that the Purchasers are relying upon the following representations and warranties in connection with their purchase of the Purchased Securities and entering into this Agreement:

4.1 Organization and Qualification

The Vendor is duly incorporated, validly existing and in good standing under the laws of its jurisdiction of incorporation.

4.2 Authority Relative to this Agreement

The Vendor has the requisite corporate authority to enter into this Agreement and to carry out its obligations hereunder. The execution and delivery of this Agreement has been duly authorized by the Vendor, and no other proceedings on the part of the Vendor are necessary to authorize the execution and delivery by it of this Agreement. This Agreement constitutes a legal, valid and binding obligation of the Vendor enforceable against the Vendor in accordance with its terms, subject to the qualification that such enforceability may be limited by bankruptcy, insolvency, reorganization or other laws of general application relating to or affecting rights of creditors and that equitable remedies, including specific performance, are discretionary and may not be ordered by a court.

4.3 Tax Matters

4.3.1 The Vendor is not a non-resident of Canada for purposes of the Tax Act.

4.3.2 No audit or other proceeding by any Governmental Authority is pending, or to the knowledge of the Vendor, threatened with respect to any Taxes due from the Vendor in respect of its ownership of the Purchased Entities and no Governmental Authority has given written notice of any intention to assert any deficiency or claim for any additional material Taxes due from or with respect to the Vendor in respect of its ownership of the Purchased Entities. There are no matters under discussion, audit or appeal with any Governmental Authority relating to Taxes due from or with respect to the Vendor in respect of its ownership of the Purchased Entities.

4.4 No Contravention

None of the entering into of this Agreement, the sale of the Purchased Securities, or the performance by the Vendor of its obligations under this Agreement do or will:

4.4.1 contravene, breach or result in any default under the Charter Documents of the Vendor;

4.4.2 except as disclosed in Schedule 5.6, violate or be in conflict with, or constitute a default under, any Contract to which the Vendor is a Party or by which the Vendor's properties or assets are or may be bound; or

4.4.3 violate any Applicable Law to which the Vendor is subject, assuming that the Regulatory Approvals are obtained,

except, in the case of Section 4.4.2 and Section 4.4.3, for such violations, conflicts or defaults which would not reasonably be expected to result in a Material Adverse Effect.

4.5 Approvals and Consents

No authorization, consent or approval of, or filing with or notice to, any Governmental Authority or other Person is required in connection with the execution, delivery or performance of this Agreement by the Vendor or the sale of any of the Purchased Securities hereunder, except for:

4.5.1 the Regulatory Approvals; and

4.5.2 such authorizations, consents, approvals, filings and notices which, if not obtained or made, would not reasonably be expected to result in a Material Adverse Effect.

4.6 Litigation and Other Proceedings

As of the date of this Agreement, there is no court, action, suit, claim, administrative, regulatory or similar proceeding (whether civil, quasi-criminal or criminal), arbitration or other dispute settlement procedure, investigation or inquiry by or before any Governmental Authority or similar body, or any similar matter or proceeding (collectively, "**Proceedings**") against or involving the Vendor (whether in progress or, to the Knowledge of the Vendor, threatened) which, if determined adversely to the Vendor, would reasonably be expected to result in a Material Adverse Effect.

4.7 No Finder's Fees

No Person acting on behalf of the Vendor or any of its Affiliates is or will be entitled to any brokerage fee, commission, finder's fee or financial advisory fee from either of the Purchasers or any of their Affiliates, the Purchased Entities or the Subsidiaries in connection with the transactions contemplated by this Agreement.

ARTICLE 5
REPRESENTATIONS AND WARRANTIES WITH RESPECT TO THE PURCHASED ENTITIES AND THE SUBSIDIARIES

Except as set forth in the Schedules to this Agreement, the Vendor represents and warrants to the Purchasers, and acknowledges that the Purchasers are relying upon the following representations and warranties in connection with their purchase of the Purchased Securities and entering into this Agreement:

5.1 Organization; Qualification; Corporate Power

Each of the Purchased Entities and each of the Subsidiaries is duly formed or incorporated, as applicable, validly existing and in good standing under the laws of its jurisdiction of formation or incorporation. Each of the Purchased Entities and each of the Subsidiaries that is a corporation has the requisite corporate power and authority to own its properties as now owned and to carry on its business as it is now being conducted. Each of the Purchased Entities and each of the Subsidiaries is duly registered or otherwise authorized to do business and is in good standing in each jurisdiction in which the character of its properties, owned, leased, licensed or otherwise held, or the nature of its activities makes such registration necessary, except where the failure to be so registered or authorized or in good standing would not be reasonably expected to result in a Material Adverse Effect. Correct and complete copies of the Charter Documents for each Purchased Entity and each Subsidiary as in effect on the date of this Agreement have been included in the Data Room.

5.2 Capital of the Purchased Entities and the Subsidiaries

Schedule 5.2 sets out the authorized and issued units or shares, as applicable, of each Purchased Entity and each Subsidiary, the names of the Persons who are the beneficial and registered owners of such units or shares, and the number and class of units or shares held by such Persons. All of the units and shares indicated on Schedule 5.2 as being issued and outstanding have been validly issued and are outstanding as fully paid and non-assessable. There are no unitholders agreements, shareholders agreements, pooling agreements, voting trusts or other agreements or understandings with respect to the voting of the units or shares, or any of them, of any Purchased Entity or any Subsidiary other than the Charter Documents of any Purchased Entity or any Subsidiary.

5.3 Subsidiaries

The Subsidiaries are the only subsidiaries (as defined in the *Business Corporations Act* (Ontario)) of the Purchased Entities.

5.4 No Obligations to Issue Securities

There are no agreements, options, warrants, rights of conversion or other rights pursuant to which any Purchased Entity or any Subsidiary is, or may become, obligated to issue any units or shares, as applicable, or any securities convertible or exchangeable, directly or indirectly, into or for any units or shares of any Purchased Entity or Subsidiary, as applicable.

5.5 Title to, and Right to Sell, Purchased Securities

The Vendor is the sole registered and beneficial owner of the Purchased Securities, in each case with good and marketable title thereto, free and clear of all Liens other than Permitted Liens. There are no agreements or restrictions which in any way limit or restrict the transfer to the Purchasers of any of the Purchased Securities other than restrictions on transfers contained in Section 10.3 and Section 11(r) of the Note Purchase Agreement, the Charter Documents of the applicable Purchased Entity and applicable securities laws. At the Closing, the Vendor will have full legal right, power and authority to sell the Purchased Securities to the Purchasers, free of all Liens other than Permitted Liens. Upon completion of the transactions contemplated by this Agreement and the payment of the Closing Payment, the Vendor will have transferred to the Purchasers good and marketable legal and beneficial title to all of the Purchased Securities free of all Liens other than Permitted Liens.

5.6 No Contravention

None of the entering into of this Agreement, the sale of the Purchased Securities or the performance by the Vendor of any of its respective obligations under this Agreement do or will:

5.6.1 contravene, breach or result in any default under the Charter Documents of any Purchased Entity or any Subsidiary;

5.6.2 except as disclosed in Schedule 5.6, violate or be in conflict with, or constitute a default under, any Contract to which any Purchased Entity or any Subsidiary is a party or by which any Purchased Entity's or any Subsidiary's properties or assets are or may be bound; or

5.6.3 violate any Applicable Law to which any Purchased Entity or any Subsidiary is subject, assuming that the Regulatory Approvals are obtained,

except, in the case of Section 5.6.2 and Section 5.6.3, for such violations, conflicts or defaults which would not reasonably be expected to result in a Material Adverse Effect.

5.7 Financial Statements

The Financial Statements have been prepared in accordance with generally accepted accounting principles consistently applied throughout the periods indicated and fairly present in all material respects the consolidated financial position of GLPT Holdings and the results of its operations as of the dates and throughout the periods indicated (subject to, in the case of the Unaudited Financial Statements: (i) normal year-end adjustments and reclassifications; and (ii) lack of footnotes and other presentation items).

5.8 Liabilities and Guarantees

None of the Purchased Entities nor any of the Subsidiaries has any outstanding Liabilities of a type required to be reflected on a balance sheet prepared in accordance with generally accepted accounting principles and none of the Purchased Entities nor any of the

Subsidiaries is a party to or bound by any agreement of guarantee, support, indemnification, assumption, or endorsement of, or any other similar commitment with respect to the Liabilities of any Person other than a Purchased Entity or a Subsidiary, except for:

5.8.1 those set out in the Financial Statements;

5.8.2 Liabilities in respect of trade or business obligations incurred after September 30, 2015 in the ordinary course of the Business, consistent with past practice;

5.8.3 Current Liabilities; and

5.8.4 Liabilities that would not reasonably expected to have a Material Adverse Effect.

5.9 Absence of Changes

Except as set forth in, or permitted by, this Agreement, since September 30, 2015: (i) the Business has been conducted in all material respects in the ordinary course of the Business, consistent with past practices; and (ii) there has not occurred a Material Adverse Effect.

5.10 Non-Arm's Length Transactions

5.10.1 Except for Contracts made solely between the Purchased Entities and the Subsidiaries and except for Contracts of employment, none of the Purchased Entities nor any of the Subsidiaries is a party to any material Contract with any current or former officer, director or employee or any Affiliate of any of the foregoing.

5.10.2 Except as disclosed in Schedule 5.10, none of the Purchased Entities nor any of the Subsidiaries is a party to any Contract with the Vendor or any of its Affiliates (other than the Purchased Entities or Subsidiaries).

5.11 Material Contracts

5.11.1 Except as disclosed in Schedule 5.11, none of the Purchased Entities nor any of the Subsidiaries is a party to or bound by any:

5.11.1.1 Contract for the purchase by any of the Purchased Entities or any of the Subsidiaries of materials, supplies or services which requires payment of more than $500,000;

5.11.1.2 Contract that is an indenture, a loan, mortgage, promissory note or agreement of guarantee, or assumption of, a similar commitment with respect to, the obligations, liabilities or indebtedness of any other Person;

5.11.1.3 Contract for the purchase or sale by any of the Purchased Entities or any of the Subsidiaries of any equipment or fixed or capital assets having a fair market value in excess of $500,000;

5.11.1.4 Contract which requires or may require the provision by any of the Purchased Entities or any of the Subsidiaries to any Person of goods or services having a fair market value in excess of $500,000;

5.11.1.5 lease, agreement in the nature of a lease or agreement to lease whether as lessor or lessee, in respect of personal property, except where the aggregate annual payments under such lease or agreement and under any related service or maintenance or similar Contract do not exceed $500,000; or

5.11.1.6 Contract, the absence of which would reasonably be expected to result in a Material Adverse Effect,

(the Contracts disclosed on Schedule 5.11, being collectively, the "**Material Contracts**").

5.11.2 None of the Purchased Entities nor any of the Subsidiaries is in default or breach in respect of any Material Contract to which it is a party or by which it may be bound and, there exists no event, occurrence, condition or fact which, with the giving of notice, the lapse of time or the happening of any other event or condition, would constitute such a default or breach, and all such Material Contracts are now in good standing and a Purchased Entity or a Subsidiary, as applicable, is entitled to all benefits, rights and privileges thereunder, except for such defaults, breaches, events, occurrences, conditions, facts and failures to be in good standing which would not reasonably be expected to result in a Material Adverse Effect. For purposes of this Section 5.11.2 only, references to Material Contracts shall not include the Leases or Identified Easements.

5.11.3 Correct and complete copies of all of the Material Contracts have been included in the Data Room.

5.12 Owned Real Property

Schedule 5.12 contains a complete and accurate legal description of all real property owned by any of the Purchased Entities or any Subsidiary (collectively, the "**Owned Real Property**"). Great Lakes Power Transmission Holding Corp. is the registered legal owner of the Owned Real Property and GLPT is the beneficial owner of the Owned Real Property and, except as disclosed in Schedule 5.12, GLPT has good and marketable title in fee simple thereto, free and clear of all Liens other than the Permitted Liens. Subject to the Permitted Liens, no Person has any agreement or right to acquire any of the Owned Real Property. The buildings and other structures located on the Owned Real Property are, when taken as a whole, adequate and suitable for the purposes for which they are currently being used.

5.13 Leases and Identified Easements

Schedule 5.13 contains a list of all Leases and Identified Easements that, to the Vendor's Knowledge, is complete and accurate, in all material respects. Except as disclosed in Schedule 5.13:

5.13.1 the Leases and Identified Easements held by the Purchased Entities and the Subsidiaries constitute good and valid rights of the Purchased Entities and the Subsidiaries, as applicable, to use the property described therein; and

5.13.2 the Leases and Identified Easements are in good standing and in full force and effect, and none of the Purchased Entities nor the Subsidiaries are in breach or default of its obligations thereunder,

except in each case for any invalidity, lack of good standing, breach, default or other occurrence that would not reasonably be expected to result in a Material Adverse Effect. Except as disclosed in Schedule 5.13, the Purchased Entities and the Subsidiaries have not received written notice of the invalidity of any Lease or Identified Easement that would be reasonably expected to result in a Material Adverse Effect.

5.14 Environmental Matters

5.14.1 Except as disclosed in Schedule 5.14 and except as would not reasonably be expected to result in a Material Adverse Effect:

5.14.1.1 each of the Purchased Entities and each of the Subsidiaries is in compliance with applicable Environmental Laws;

5.14.1.2 all Environmental Permits obtained by any Purchased Entity or any Subsidiary in connection with the Business are listed in Schedule 5.14;

5.14.1.3 there are no Substances in, on or under the Premises that are currently required to be remediated under Environmental Law; and

5.14.1.4 there are no Proceedings against or involving any Purchased Entity or any Subsidiary, either in progress, pending or to the Knowledge of the Vendor, threatened, which allege a violation of, or non-compliance with, applicable Environmental Laws.

5.14.2 Notwithstanding anything in this Agreement to the contrary, the representations and warranties made by the Vendor in this Section 5.14 and in Section 5.21 are the sole and exclusive representations and warranties made regarding: (i) environmental and occupational health and safety matters; (ii) matters of any kind relating to Environmental Laws or Environmental Permits; and (iii) conditions, Liabilities and/or Losses arising from such matters.

5.15 Aboriginal Matters

Except for the Permitted Encumbrances and except as set forth in Schedule 5.15, there has not been made or brought by any Governmental Authority, or any aboriginal Person or group (including any Indian Band), by virtue of its aboriginal status, any of the following which could reasonably be expected to result in a Material Adverse Effect:

5.15.1 any claim or proceeding in respect of any right, title, benefit or interest in the Premises or any assets of the Business;

5.15.2 any claim of jurisdiction over the Business; or

5.15.3 any claim of a failure to be consulted or accommodated with respect to any use, development or improvement of the Owned Real Property.

5.16 Tax

5.16.1 Except as disclosed on Schedule 5.16:

5.16.1.1 all material Tax Returns required by Applicable Law to be filed by or with respect to each of the Purchased Entities and the Subsidiaries have been timely filed and all required income and all other amounts and information have been duly, completely and correctly reported thereon and all amounts of taxes owed by the Purchased Entities and the Subsidiaries have either been paid or adequate provision therefor in accordance with IFRS in the Financial Statements or in their respective books and records.

5.16.1.2 each of the Purchased Entities and each of the Subsidiaries has timely paid or caused to be timely paid, all Taxes that are due and payable (whether or not shown due on any Tax Returns and whether or not assessed (or reassessed) by the appropriate Governmental Authority). All assessments and reassessments received by any of the Purchased Entities or any of the Subsidiaries in respect of Taxes have been paid;

5.16.1.3 adequate provision has been made by each of the Purchased Entities and each of the Subsidiaries, in accordance with IFRS, in the Financial Statements or in their respective books and records for all Taxes for any period for which Tax Returns are not yet required to be filed, or for which Taxes are not yet due or payable;

5.16.1.4 no audit or other proceeding by any Governmental Authority is pending or, to the Knowledge of the Vendor, threatened with respect to any Taxes due from any of the Purchased Entities or any of the Subsidiaries, and no Governmental Authority has given written notice of any intention to assert any deficiency or claim for additional material Taxes against any of the Purchased Entities or any of the Subsidiaries. There are no matters under discussion, audit or appeal with any Governmental Authority relating to Taxes due from or with respect to any of the Purchased Entities or any of the Subsidiaries;

5.16.1.5 no Governmental Authority of a jurisdiction in which any of the Purchased Entities or any of the Subsidiaries does not file Tax Returns has made any written claim that such entity is or may be subject to taxation by such jurisdiction. To the Knowledge of the Vendor, there is no basis for a claim that any of the Purchased Entities or any of the Subsidiaries is subject to Tax in a jurisdiction in which it does not file Tax Returns;

5.16.1.6 there are no outstanding agreements, waivers, objections or arrangements extending the statutory period of limitations applicable to any claim for Taxes due from or with respect to any of the Purchased Entities or any of the Subsidiaries for any taxation period, nor has any such agreement, waiver, objection or arrangement been requested. None of the Purchased Entities nor any of the Subsidiaries is bound by any tax sharing, allocation or indemnification or similar agreement;

5.16.1.7 the Purchased Entities and the Subsidiaries have withheld or collected the proper amount of Taxes in all material respects that are required by Applicable Law to be withheld or collected and have timely remitted the proper amount of any Taxes in all material respects that have been withheld or collected, and are due, to the applicable Governmental Authority; and

5.16.1.8 notwithstanding anything in this Agreement to the contrary, the representations and warranties made by the Vendor in Section 4.3 and this Section 5.16 are the sole and exclusive representations and warranties made regarding Taxes or other Tax matters.

5.17 Employment Matters and Collective Agreements

5.17.1 Except as disclosed on Schedule 5.17, as of the date hereof, none of the Purchased Entities nor any of the Subsidiaries is a party to or bound by, subject to, or affected by, any:

5.17.1.1 Contract for the employment or retainer of any individual which provides for annual payments of more than $300,000 to any single individual;

5.17.1.2 retention bonus agreement or employment Contract providing for cash or other compensation or benefits upon the consummation of the transactions contemplated by this Agreement;

5.17.1.3 Contract with any trade union, council of trade unions, employee bargaining agent or affiliated bargaining agent (collectively, "**Labour Representatives**") and none of the Purchased Entities nor any of the Subsidiaries has conducted negotiations with respect to any such future Contracts; to the Knowledge of the Vendor, no Labour Representatives hold bargaining rights with respect to any employees of any Purchased Entity or any Subsidiary; and there are no current or, to the Knowledge of the Vendor, threatened attempts to organize or establish any trade union or employee association with respect to a Purchased Entity or any Subsidiary; or

5.17.1.4 actual or, to the Knowledge of the Vendor, threatened material Proceeding arising out of or in connection with employment or retention by any of the Purchased Entities or any of the Subsidiaries of an employee or the termination thereof.

5.17.2 Correct and complete copies of all of the Contracts set out in Schedule 5.17 have been included in the Data Room.

5.17.3 Except as disclosed on Schedule 5.17, there is no work stoppage or other material concerted action, grievance or dispute existing or, to the Knowledge of the Vendor, threatened against any Purchased Entity or any Subsidiary with respect to any of its employees that would be reasonably expected to result in a Material Adverse Effect.

5.17.4 Except for the Collective Agreements, none of the Purchased Entities nor any of the Subsidiaries are a party to or bound by or subject to any agreement with any labour union or employee association and have not made any commitment to or conducted any negotiation or discussion with any labour union or employee association with respect to any future agreement or arrangement. There is no strike or lockout occurring, or to the Knowledge of the Vendor, threatened against any of the Purchased Entities or Subsidiaries.

5.18 Employee Plans

5.18.1 Schedule 5.18 sets forth all material Employee Plans as of the date of this Agreement. The Vendor has made available to the Purchasers copies of each Employee Plan, including plan documents and all material documents that support each Employee Plan.

5.18.2 Each Employee Plan is maintained, operated and administered in material compliance with Applicable Laws and with the terms of such Employee Plan, except where the failure to so comply would not reasonably be expected to have a Material Adverse Effect.

5.19 Insurance

5.19.1 Schedule 5.19 contains a list of all insurance policies under which any of the assets or business activities of any of the Purchased Entities or any of the Subsidiaries are covered as of the date hereof (the "**Insurance Policies**").

5.19.2 As of the date hereof, all Insurance Policies are in full force and effect, all insurance premiums due thereon have been paid in full when due and no written notice of cancellation, non-renewal or termination, or any written notice threatening cancellation, non-renewal or termination, has been received by any Purchased Entity or Subsidiary. The Purchased Entities and Subsidiaries are in compliance with the terms and conditions of the Insurance Policies, except failures so to comply which would not reasonably be expected to have a Material Adverse Effect.

5.20 Intellectual Property

Except as would not reasonably be expected to have a Material Adverse Effect: (i) the Purchased Entities and each of the Subsidiaries owns or has the right to use all patents, trade secrets, trademarks, trade names, service marks, copyrights and other intellectual property used in the Business as currently conducted; and (ii) none of the Purchased Entities nor their Subsidiaries have received written notice of any pending claim that the conduct of the Business as currently conducted infringes or otherwise violates the intellectual property rights of any third party.

5.21 Permits

Except as set forth in Schedule 5.21, each of the Purchased Entities and each of the Subsidiaries hold all material Permits necessary for the lawful operation of the Business pursuant to all Applicable Laws of all Governmental Authorities having jurisdiction over the Purchased Entities and Subsidiaries except for such Permits, the failure of which to have, would not reasonably be expected to result in a Material Adverse Effect (the "**Required Permits**"). Except as set forth in Schedule 5.21, each Required Permit is valid, binding and in full force and effect, and no Purchased Entity or Subsidiary is in material default under any Required Permit.

5.22 Compliance with Laws

The Purchased Entities and the Subsidiaries are conducting the Business in compliance with all Applicable Laws (except for the representations and warranties set out in Section 5.14, which are addressed exclusively by the terms therein), except for such non-compliance which would not reasonably be expected to result in a Material Adverse Effect.

5.23 Litigation and Other Proceedings

There are no Proceedings against or involving any Purchased Entity or any Subsidiary (whether in progress or, to the Knowledge of the Vendor, threatened) which, if determined adversely to a Purchased Entity or a Subsidiary would reasonably be expected to result in a Material Adverse Effect; to the Knowledge of the Vendor, no event has occurred which might give rise to any such Proceedings; and there is no judgment, decree, injunction, rule, award or order of any Governmental Authority outstanding against any Purchased Entity or any Subsidiary, which would reasonably be expected to result in a Material Adverse Effect.

5.24 Assets

5.24.1 The Purchased Entities and/or the Subsidiaries, as the case may be, own the Assets that are purported to be owned by them, or shown on the Financial Statements or acquired by the Purchased Entities or Subsidiaries after September 30, 2015, free and clear of any Liens except Permitted Liens, except where failure to hold such rights would not reasonably be expected to result in a Material Adverse Effect.

5.24.2 Except as would not reasonably be expected to result in a Material Adverse Effect or listed as items 5 through 14, inclusive, in the Schedule entitled "Issues with respect to Leases and Identified Easements" that forms part of Schedule 5.13, the Assets are sufficient for the continued conduct of the Business after the Closing in the same manner as conducted before the Closing and constitute all of the rights, property and assets necessary to conduct the Business consistent with past practice.

5.24.3 Except as set forth in Schedule 5.24, the only assets owned by: (i) GLPT Holdings II are all of the issued and outstanding limited partnership units of GLPT Holdings (which it owns free and clear of all Liens other than Permitted Liens) and GLPT Holdings II has no other rights or interests in any other assets (other than any distributions declared on the limited partnership units), no other operations and has no outstanding Liabilities; (ii) GLPT Holdings GP are all of the issued and outstanding general partner units of GLPT Holdings and GLPT Holdings II (each of which it owns free and clear of all Liens other than Permitted Liens) and GLPT Holdings GP has no other rights or interests in any other assets, no other operations and has no outstanding Liabilities; and (iii) GLPT GP are all of the issued and outstanding general partner units of GLPT and GLPT GP has no rights or interests in any other assets, no other operations and has no outstanding Liabilities except solely in its capacity as general partner of GLPT in respect of the Business.

5.24.4 To the Knowledge of the Vendor, except as disclosed in Schedule 5.13 and except to the extent that the absence of any right to use or occupy would not result in a Material Adverse Effect, the Purchased Entities and/or Subsidiaries have the right to use or occupy the lands upon which the Assets required to operate the Business are located.

ARTICLE 6
REPRESENTATIONS AND WARRANTIES OF THE PURCHASERS

The Purchasers jointly and severally represent and warrant to the Vendor as follows and acknowledge that the Vendor is relying upon the following representations and warranties in connection with the sale of the Purchased Securities and entering into this Agreement:

6.1 Organization; Qualification; Corporate Power

6.1.1 The Unit Purchaser is duly incorporated, validly existing and in good standing under the laws of its jurisdiction of incorporation and has the requisite corporate power and authority to own its properties as now owned and to carry on its business as it is now being conducted. The Unit Purchaser is duly registered or otherwise authorized to do business and is in good standing in each jurisdiction in which the character of its properties, owned, leased, licensed or otherwise held, or the nature of its activities makes such registration necessary, except where the failure to be so registered or authorized or in good standing would not materially adversely affect the Unit Purchaser's ability to perform its obligations under this Agreement.

6.1.2 The Share Purchaser is duly incorporated, validly existing and in good standing under the laws of its jurisdiction of incorporation and has the requisite corporate power and authority to own its properties as now owned and to carry on its business as it is now being conducted. The Share Purchaser is duly registered or otherwise authorized to do business and is in good standing in each jurisdiction in which the character of its properties, owned, leased, licensed or otherwise held, or the nature of its activities makes such registration necessary, except where the failure to be so registered or authorized or in good standing would not materially adversely affect the Share Purchaser's ability to perform its obligations under this Agreement.

6.2 Authority Relative to this Agreement

Each Purchaser has the requisite authority to enter into this Agreement and to carry out its obligations hereunder. The execution and delivery of this Agreement has been duly authorized by the Purchasers, and no other proceedings on the part of the Purchasers are necessary to authorize the execution and delivery by them of this Agreement. This Agreement constitutes a legal, valid and binding obligation of the Purchasers enforceable against the Purchasers in accordance with its terms, subject to the qualification that such enforceability may be limited by bankruptcy, insolvency, reorganization or other laws of general application relating to or affecting rights of creditors and that equitable remedies, including specific performance, are discretionary and may not be ordered by a court.

6.3 Approvals and Consents

6.3.1 Except for the Regulatory Approvals, no authorization, consent or approval of, or filing with or notice to, any Governmental Authority or other Person is required in connection with the execution, delivery or performance of this Agreement by the Purchasers or the purchase of any of the Purchased Securities hereunder.

6.3.2 [redacted]

6.4 Independent Investigation

Each Purchaser has conducted its own independent investigation, review and analysis of the Business, results of operations, prospects, condition (financial or otherwise) and assets of the Purchased Entities and the Subsidiaries, and acknowledges that it has been provided adequate access to the personnel, properties, assets, premises, books and records and other documents and data of the Vendor, the Purchased Entities and the Subsidiaries for such purpose. Each Purchaser acknowledges and agrees that:

6.4.1 in making its decision to enter into this Agreement and to consummate the transactions contemplated hereby, each Purchaser has relied solely upon its own investigation and the express representations and warranties of the Vendor set forth in this Agreement (including the related portions of the Schedules);

6.4.2 none of the Vendor, the Purchased Entities, the Subsidiaries, any of their respective Affiliates or any other Person has made any representation or warranty, express or implied, at Applicable Law or in equity or otherwise, with respect to the Vendor, any of its Affiliates, the Purchased Entities, the Subsidiaries, the Purchased Securities, this Agreement, the Business, the financial condition, Liabilities or assets (including as regards to their condition, value, quality, merchantability, usage, suitability or fitness for any particular purpose) of any of the Purchased Entities or any of the Subsidiaries, or with respect to any other information (oral or written) provided to a Purchaser or any of its Affiliates, whether by or on behalf of the Vendor, except as expressly set forth in this Agreement (including the related portions of the Schedules), and any and all such representations and warranties which are not expressly set forth in this Agreement (including the related portions of the Schedules) are hereby waived and excluded; and

6.4.3 except as expressly set forth in this Agreement (including the related portions of the Schedules), none of the Vendor, any Purchased Entity, any of the Subsidiaries, nor any of their respective Affiliates make any representation, warranty or covenant of any kind with respect to any projections, estimates or budgets heretofore delivered to or made available to either Purchaser, any of their respective Affiliates or any of their respective representatives of future revenues, expenses or expenditures, future results of operations (or any component thereof) of the Purchased Entities and the Subsidiaries or the future business and operations of the Purchased Entities and the Subsidiaries.

6.5 Litigation and Other Proceedings

As of the date of this Agreement, there are no Proceedings against or involving either Purchaser (whether in progress or, to the Knowledge of the Purchasers, threatened) which, if determined adversely to either Purchaser, would have a material adverse effect with respect to the ability of either Purchaser to perform its obligations under this Agreement; to the best of the Purchasers' Knowledge, no event has occurred which might give rise to any such Proceedings; and there is no judgment, decree, injunction, rule, award or order of any Governmental Authority outstanding against or affecting either Purchaser or any of its respective properties or assets, which would reasonably be expected to materially and adversely affect the ability of either Purchaser to perform its obligations under this Agreement.

6.6 No Contravention

None of the entering into of this Agreement, the purchase of the Purchased Securities or the performance by each Purchaser of its other obligations under this Agreement do or will:

6.6.1 contravene, breach or result in any default under the Charter Documents of either Purchaser;

6.6.2 violate or be in conflict with, or constitute a default under, any Contract to which either Purchaser is a party or by which either Purchaser's properties or assets are or may be bound; or

6.6.3 violate any Applicable Law to which either Purchaser is subject, assuming that the Regulatory Approvals are obtained,

except, in the case of Section 6.6.2 and Section 6.6.3, for such violations, conflicts or defaults which would not have a material adverse effect with respect to the ability of either Purchaser to perform its obligations under this Agreement.

6.7 Sufficiency of Funds

The Purchasers have sufficient cash on hand or other sources of immediately available funds to enable them to make payment of the Purchase Price and consummate the transactions contemplated by this Agreement.

6.8 Solvency

Neither Purchaser is insolvent. Neither Purchaser is subject to receivership, liquidation, moratorium or the jurisdiction of a bankruptcy court or trustee. There are no bankruptcy, reorganization or arrangement Proceedings pending against, being contemplated by, or, to the Knowledge of the Purchasers, threatened against either Purchaser.

6.9 No Finder's Fees

No Person acting on behalf of either Purchaser or any of its Affiliates is or will be entitled to any brokerage fee, commission, finder's fee or financial advisory fee from the Vendor or any of its Affiliates in connection with the transactions contemplated by this Agreement.

6.10 Tax Matters

Neither Purchaser is a Person described in any of paragraphs 100(1.1)(a) to (d) of the Tax Act. The Purchasers have no intention to effect any transfer of any of the Purchased Units to any Person described in any of paragraphs 100(1.1)(a) to (d) of the Tax Act or any transaction whereby any such Person would contribute capital to any Purchased Entity or any Subsidiary that is a partnership for an interest in any partnership with a corresponding distribution to either Purchaser.

ARTICLE 7
REPRESENTATIONS AND WARRANTIES OF BIP

BIP represents and warrants to the Purchasers, and acknowledges that the Purchasers are relying upon the following representations and warranties in connection with their purchase of the Purchased Securities and entering into this Agreement:

7.1 Organization and Qualification

BIP is duly formed, validly existing and in good standing under the laws of laws of its jurisdiction of formation.

7.2 Authority Relative to this Agreement

BIP has the requisite authority to enter into this Agreement and to carry out its obligations hereunder. The execution and delivery of this Agreement has been duly authorized by BIP, and no other proceedings on the part of BIP are necessary to authorize the execution and delivery by it of this Agreement. This Agreement constitutes a legal, valid and binding obligation of BIP enforceable against BIP in accordance with its terms, subject to the qualification that such enforceability may be limited by bankruptcy, insolvency, reorganization or other laws of general application relating to or affecting rights of creditors and that equitable remedies, including specific performance, are discretionary and may not be ordered by a court.

7.3 No Contravention

None of the entering into of this Agreement, the sale of the Purchased Securities, or the performance by BIP of its obligations under this Agreement do or will:

7.3.1 contravene, breach or result in any default under the Charter Documents of BIP;

7.3.2 violate or be in conflict with, or constitute a default under, any Contract to which BIP is a Party or by which BIP's properties or assets are or may be bound; or

7.3.3 violate any Applicable Law to which BIP is subject, assuming that the Regulatory Approvals are obtained,

except, in the case of Section 7.3.2 and Section 7.3.3, for such violations, conflicts or defaults which would not reasonably be expected to materially adversely affect BIP's ability to perform its obligations under the Agreement.

ARTICLE 8
CONDITIONS

8.1 Conditions for the Benefit of the Purchasers

The obligation of the Purchasers to complete the purchase of the Purchased Securities pursuant to this Agreement is subject to the satisfaction of, or compliance with, at or prior to the Closing, each of the following conditions (each of which is acknowledged to be for the exclusive benefit of the Purchasers and may be waived, in whole or in part, by the Purchasers):

8.1.1 Accuracy of Representations and Warranties of the Vendor

The representations and warranties of each of the Vendor and BIP contained in this Agreement shall be true and correct in all material respects (except for such representations and warranties that are qualified as to materiality or Material Adverse Effect, which shall be true and correct in all respects) as of the Closing Date with the same force and effect as if such representations and warranties had been made on and as of the Closing Date (except for such representations and warranties that are made as of a specified date in which case they shall be true and correct in all material respects (except for such representations and warranties that are qualified as to materiality or Material Adverse Effect, which shall be true and correct in all respects) as of the specified date), and each of the Vendor and BIP shall have executed and delivered a certificate of a senior officer to that effect in favour of the Purchasers.

8.1.2 Compliance With Covenants

The Vendor shall have fulfilled or complied, in all material respects, with all of the covenants contained in this Agreement to be fulfilled or complied with by the Vendor at or prior to the Closing, and the Vendor shall have executed and delivered a certificate of a senior officer to that effect in favour of the Purchasers.

8.1.3 Closing Documents

The Purchasers shall have received the agreements, instruments and documents required to be delivered by the Vendor under Section 3.2.1.

8.1.4 No Action to Restrain

No Proceeding or order shall be issued or pending by any Governmental Authority or Person (other than the Purchasers or any Affiliate thereof) to restrain, enjoin or prohibit the purchase and sale of the Purchased Securities hereunder.

8.1.5 Regulatory Approvals

The Regulatory Approvals shall have been obtained in accordance with the terms of this Agreement.

8.1.6 No Material Adverse Effect

There shall not have occurred a Material Adverse Effect.

8.2 Conditions for the Benefit of the Vendor

The obligation of the Vendor to complete the sale of the Purchased Securities pursuant to this Agreement is subject to the satisfaction of, or compliance with, at or prior to the Closing, each of the following conditions (each of which is acknowledged to be for the exclusive benefit of the Vendor and may be waived, in whole or in part, by the Vendor):

8.2.1 Accuracy of Representations and Warranties of Purchasers

The representations and warranties of the Purchasers contained in this Agreement shall be true and correct in all material respects (except for such representations and warranties that are qualified as to materiality, which shall be true and correct in all respects) as of the Closing Date with the same force and effect as if such representations and warranties had been made on and as of the Closing Date (except for such representations and warranties that are made as of a specified date in which case they shall be true and correct in all material respects (except for such representations and warranties that are qualified as to materiality, which shall be true and correct in all respects) as of the specified date), and each Purchaser shall have executed and delivered a certificate of a senior officer to that effect in favour of the Vendor.

8.2.2 Compliance With Covenants

The Purchasers shall have fulfilled or complied, in all material respects, with all of the covenants contained in this Agreement to be fulfilled or complied with by the Purchasers at or prior to the Closing, and each Purchaser shall have executed and delivered a certificate of a senior officer to that effect in favour of the Vendor.

8.2.3 Closing Documents

The Vendor shall have received the agreements, instruments and documents required to be delivered by the Purchasers under Section 3.2.2.

8.2.4 No Action to Restrain

No Proceeding or order shall be issued or pending by any Governmental Authority or Person (other than the Vendor or any Affiliate thereof) to restrain, enjoin or prohibit the purchase and sale of the Purchased Securities hereunder.

8.2.5 Regulatory Approvals

The Regulatory Approvals shall have been obtained in accordance with the terms of this Agreement.

ARTICLE 9
ADDITIONAL COVENANTS OF THE PARTIES

9.1 Access to Information

9.1.1 The Vendor shall cause each of the Purchased Entities and each of the Subsidiaries to provide, until the Closing Date, to the Purchasers and their representatives, at the sole cost and expense of the Purchasers, during normal business hours such access to their premises, assets, books, accounts, Tax Returns, Contracts and records and to their personnel and to furnish them with such information relating to the Business and their affairs and assets, in each case as the Purchasers may reasonably request, unless: (i) that information is competitively sensitive information; or (ii) the Vendor otherwise reasonably determines in respect thereof that disclosure should be restricted, in which case the Vendor may restrict the provision of such information to the Purchasers' external legal counsel.

9.1.2 Without limiting Section 10.4.3.3, the Purchasers shall, and shall cause each of the Purchased Entities and each of the Subsidiaries to, retain and preserve the books and records, accounts, minute books, Tax Returns, documents, instruments, and Contracts of each of the Purchased Entities and each of the Subsidiaries for a period of seven years from the Closing Date, or for such longer period as may be required by any Applicable Laws or any Governmental Authority. The Purchasers shall provide the Vendor and its accountants, legal advisers and representatives during normal business hours with reasonable access to such books and records, accounts, minute books, Tax Returns, documents, instruments, and Contracts of each of the Purchased Entities and each of the Subsidiaries, at no cost to the Vendor, and shall allow the Vendor to take copies of any such books and records, minute books, Tax Returns, documents, instruments, and Contracts (or, where an original copy is required by a Governmental Authority, the Vendor may provide a copy to the Purchasers in exchange for an original thereof), at the expense of the Vendor, in each case on a timely basis and as may be reasonably required by the Vendor in connection with any obligations of the Vendor under Applicable Laws or to a Governmental Authority.

9.2 Conduct of Business Until Time of Closing

9.2.1 From the date of this Agreement until the Closing, except as set forth in Schedule 9.2 or otherwise provided in this Agreement or consented to in writing by the Purchasers (which consent shall not be unreasonably withheld, delayed or conditioned), the Vendor shall cause the Purchased Entities and the Subsidiaries to: (i) conduct the Business in the ordinary course of the Business consistent with past practice; and (ii) use Commercially Reasonable Efforts to maintain and preserve intact the current organization, business and franchise of the Purchased Entities and the Subsidiaries and to preserve the rights, franchises, goodwill and relationships of its employees, customers, lenders, suppliers, distributors and others having business relationships with the Purchased Entities and/or the Subsidiaries.

9.2.2 Without limiting the generality of Section 9.2.1, from the date of this Agreement until the Closing, except as set forth in Schedule 9.2 or otherwise provided in this Agreement or consented to in writing by the Purchasers (which consent shall not be unreasonably withheld, delayed or conditioned), the Vendor shall cause the Purchased Entities and the Subsidiaries, as applicable, to:

9.2.2.1 maintain insurance upon all of their assets comparable in amount, scope and coverage to that in effect on the date of this Agreement;

9.2.2.2 maintain their books, records and accounts in the ordinary course of the Business, consistent with past practice;

9.2.2.3 not amalgamate, merge or consolidate with, or acquire all or substantially all the shares of, any Person;

9.2.2.4 pay and discharge the Liabilities of the Purchased Entities and the Subsidiaries in the ordinary course of the Business, consistent with past practice, except those being contested in good faith;

9.2.2.5 not incur or not assume any Liability except unsecured current obligations and liabilities incurred in the ordinary course of business, consistent with past practice and not to create or not to permit to exist any Liens affecting any of their assets or property, except for Permitted Liens;

9.2.2.6 not amend, terminate or cancel, or cause to amend, terminate or cancel, the Charter Documents of any of the Purchased Entities or any of the Subsidiaries;

9.2.2.7 comply in all material respects with their covenants and obligations under the Material Contracts;

9.2.2.8 other than in the ordinary course of the Business, consistent with past practice, not enter into any Contract which would be a "Material Contract" pursuant to Section 5.11.1, other than any renewal of any customer Contracts in effect as of the date hereof on substantially similar terms;

9.2.2.9 not make any material increase in the compensation payable or to become payable to its directors, officers or employees, including any improvements to severance or termination pay or changes to Employee Plans, except as required by Applicable Laws or the terms of the Collective Agreements, other than general salary increases and bonus payments in the ordinary course of the Business, consistent with past practice;

9.2.2.10 hire, reassign or dismiss any senior management employee;

9.2.2.11 not issue any securities or other ownership interests or directly or indirectly redeem, offer to purchase or purchase any outstanding securities of any of the Purchased Entities or any of the Subsidiaries;

9.2.2.12 not grant any options, warrants, convertible securities or rights to acquire or subscribe for any securities of any of the Purchased Entities or any of the Subsidiaries;

9.2.2.13 other than in the ordinary course of the Business or pursuant to a Material Contract, consistent with past practice, not acquire any assets (through one or more related or unrelated acquisitions) having a value in excess of $2,000,000 in the aggregate for all such transactions; and

9.2.2.14 other than in the ordinary course of the Business, consistent with past practice, not sell, lease, option, create or grant any Lien in respect of, or otherwise dispose of any assets (through one or more related or unrelated transactions) having a value in excess of $1,000,000 in the aggregate for all such transactions.

9.2.3 Notwithstanding any provision of this Agreement to the contrary, prior to the Closing, except to the extent prohibited by Applicable Law or the term of any Contract, the Purchased Entities and the Subsidiaries shall be permitted to dividend, distribute and/or otherwise transfer to the Vendor all cash, cash equivalents, bank deposits and certificates of deposit owned or otherwise held by any Purchased Entity or any Subsidiary.

9.3 Insurance

The Purchasers acknowledge and agree that the Insurance Policies shall terminate at and as of the Closing and from and after the Closing Date, Purchasers shall be solely responsible for any risk of loss based on claims pending as of the Closing Date and for providing, or causing the Purchased Entities and the Subsidiaries to provide, all insurance coverage for and with respect to the Purchased Entities and the Subsidiaries and their respective businesses, assets and current employees, and for making any claims under such insurance coverage or, to the extent permitted by the terms thereof, any claims under the Insurance Policies, in each case without regard to when the event giving rise to any such claim occurred.

9.4 Certain Tax Covenants

9.4.1 Between the date of this Agreement and the Closing Date, the Vendor shall:

9.4.1.1 not permit any of the Purchased Entities or any of the Subsidiaries to revoke any Tax election, or make an election inconsistent with past Tax reporting, or file an amended Tax Return unless required by Applicable Law;

9.4.1.2 not permit any of the Purchased Entities or any of the Subsidiaries to make any change in any Tax or accounting methods or policies or systems of internal accounting controls, except as may be appropriate to conform to changes in Applicable Laws related to Taxes or regulatory accounting requirements or generally accepted accounting principles; and

9.4.1.3 advise the Purchasers, or cause each Purchased Entity and each Subsidiary to advise the Purchasers, promptly in writing if it becomes aware of any Proceeding pending against or with respect to: (i) the Vendor in respect of its ownership of the Purchased Entities; (ii) a Purchased Entity; or (iii) a Subsidiary, in respect of any Tax matter.

9.4.2 The Vendor shall prepare, or cause to be prepared, all Tax Returns relating to a Pre-Closing Tax Period required by Applicable Law to be filed by the Purchased Entities and the Subsidiaries after the Closing Date and in a manner consistent with past practice unless otherwise required by Applicable Law. The Purchasers shall be given the opportunity to review, comment upon and suggest changes or corrections to, such Tax Returns prior to the filing thereof (but in no event less than 30 days prior to such filing). The Purchasers shall, and shall cause the Purchased Entities and the Subsidiaries to, fully cooperate with and assist the Vendor (including allowing access by the Vendor and its representatives to the books and records (written and electronic) of the Purchased Entities and the Subsidiaries and allowing the Vendor and its representatives to make copies thereof) in connection with the preparation by the Vendor of any such Tax Returns (and any Tax Returns required by Applicable Laws to be filed by the Vendor and its direct or indirect owners) and the Vendor and its representatives shall not be charged with any cost or expense for the assistance rendered by the Purchaser or any of the Purchased Entities or any of the Subsidiaries in connection therewith.

9.4.3 Except as required by Applicable Laws or where the written consent of the Vendor (not to be unreasonably withheld, conditioned or delayed) is provided, the Purchasers shall not cause to be filed, refiled, amended or otherwise modified, and the Purchasers shall cause each of the Purchased Entities and each of the Subsidiaries to not file, refile, amend or otherwise modify, any Tax Return of any of the Purchased Entities or any of the Subsidiaries for a Pre-Closing Tax Period or any other taxation year or period that begins before the Closing Date. For greater certainty, none of the Purchasers, the Purchased Entities nor the Subsidiaries shall make any Tax election which may take effect or be deemed to take effect on a date on or prior to the Closing Date with respect to any of the Purchased Entities or the Subsidiaries without the prior written consent of the Vendor.

9.4.4 For all purposes under this Agreement, in the case of any Tax period that includes but does not end on the Closing Date (a "**Straddle Period**"), the portion of Taxes (or any Tax refund and amount credited against any Tax) that are allocable to the portion of the Straddle Period ending at the end of the Closing Date will be: (i) in the case of property Taxes and other Taxes imposed on a periodic basis without regard to income, gross receipts, payroll or sales, deemed to be the amount of such Taxes (or Tax refund or amount credited against Tax) for the entire Straddle Period multiplied by a fraction, the numerator of which is the number of calendar days in the portion of such Straddle Period ending at the end of the Closing Date and the denominator of which is the number of calendar days in the entire Straddle Period; and (ii) in the case of all other Taxes, determined as though the taxable year of the Purchased Entities terminated at the end of the Closing Date. Any deductions that relate to or are in respect of the Closing shall be reflected in the portion of any Straddle Period ending at the end of the Closing Date (if not otherwise deemed to end at the time of Closing under the Tax Act). The taxable income for the Straddle Period shall be computed in a manner consistent with previous tax returns claiming the maximum deductions pursuant to the Tax Act. Any deductions that relate to or are in respect of the Closing shall be reflected in the portion of any Straddle Period ending at the end of the Closing Date.

9.4.5 The Parties shall cause the Purchased Entities and the Subsidiaries to claim capital cost allowance and other discretionary deductions in respect of any Straddle Period in a manner consistent with past practice. The Purchasers shall cause the Purchased Entities and the Subsidiaries to provide, on a timely basis, information to the Vendor and to the Purchasers as to the Vendor's and the Purchasers' allocation of loss (or income), if any, for the Straddle Period and the Vendor's and the Purchasers' share of federal and provincial Taxes withheld or paid on account of income of GLPT, Purchased Entities and the Subsidiaries. The Parties agree that the Vendor and the Purchasers shall each be entitled to claim and keep refunds of its respective allocated share of such Taxes for the Straddle Period and prior fiscal periods. The Purchasers shall, upon request from the Vendor and with commercially reasonable diligence, cooperate with the Vendor in providing information to the CRA and provincial Tax authorities in support of such refund claims.

9.4.6 The amount of any refunds of Taxes (including any interest paid with respect thereto and, for greater certainty, any amount otherwise refundable which is applied towards a payment of Tax attributable to a taxable period ending after the Closing Date to a Governmental Authority but net of any Taxes payable by a Purchaser Indemnified Party in respect of such refund or interest that would have been payable in the absence of use of a loss or credit from a tax period that is not a Pre-Closing Tax Period) of, or with respect to, any of the Purchased Entities or any of the Subsidiaries for any Pre-Closing Tax Period will be treated as additional purchase price for the Purchased Securities (except to the extent such refunds were taken into account in computing the Final Working Capital and except to the extent such refunds arise as a result of the carryback of a loss or credit from a tax period that is not a Pre-Closing Tax Period) which shall be allocated to the Vendor. The Purchasers shall pay an amount equal to the amount of any such refunds to the Vendor within 30 days following the date such refunds were paid or credited by the relevant Governmental Authority to such Purchased Entity or such Subsidiary, as applicable.

9.4.7 Except as required pursuant to Section 9.4.8, from and after the Closing Date, the Purchasers shall not, without the prior written consent of the Vendor, amend or modify, or cause or permit the amendment or modification of, in whole or in part, the partnership agreement of any Purchased Entity or a Subsidiary, until such time as the net income and net loss of any one of them that is a partnership, as applicable, for the fiscal period in which the Closing Date occurs has been allocated in accordance with the terms of any such partnership agreement, as applicable, as such terms are amended pursuant to Section 9.4.8.

9.4.8 The Parties shall amend or modify, or cause the amendment or modification of, in whole or in part, the partnership agreement of any Purchased Entity or any Subsidiary as required to reflect Section 9.4.4.

9.4.9 If the Purchasers propose to undertake any transaction of the type described in Section 6.10 within three years of the Closing Date (or enter into any negotiations, agreements, understandings or arrangements with respect to such a transaction), the Purchasers shall not undertake such transaction (or such negotiations, agreements, understandings or arrangements) without first: (i) obtaining an advance income tax ruling from the CRA or an opinion of a nationally recognized law firm (which income tax ruling or opinion, as applicable, shall be addressed to, and which income tax ruling shall be binding on, the Vendor) that provides that such transaction will not cause subsection 100(1) of the Tax Act to apply in respect of the disposition of the Purchased Securities by the Vendor hereunder, and which tax ruling or opinion shall be in form and substance satisfactory to the Vendor, acting reasonably; and (ii) providing a copy of such tax ruling or opinion to the Vendor.

9.4.10 Without in any way limiting Section 9.4.9, for a period of three years after the Closing Date, the Purchasers shall not effect any transfer of any of the Purchased Units to any Person or any transaction whereby any Person would contribute capital to any partnership in exchange for an interest in the partnership with a corresponding distribution to the Purchasers unless such Person provides the representation in Section 6.10 to the Vendor and the covenant in Section 9.4.9 to the Vendor, and the Purchasers agree to be liable to the Vendor for any breach of such representation or covenant.

9.5 Transfer Taxes

All transfer, registration, stamp, documentary, sales, use and similar Taxes (including all applicable land transfer Taxes), any penalties, interest and additions to Tax, and fees incurred in connection with the transactions contemplated by this Agreement (collectively, "**Transfer Taxes**") shall be the sole responsibility of and be timely paid by the Purchasers. The Vendor and the Purchasers shall cooperate in the timely making of all filings, Tax Returns, reports and forms as may be required in connection with any Transfer Tax.

9.6 Replacement of Letters of Credit and Note Purchase Agreement

9.6.1 The Purchasers acknowledge that the Vendor or an Affiliate thereof has provided the letters of credit in respect of liabilities or obligations of a Purchased Entity or a Subsidiary, all as set out in Schedule 9.6 (collectively, the "**Vendor Letters of Credit**"). The Parties agree that, at the Closing:

9.6.1.1 the Purchasers shall deliver letters of credit (the "**Replacement Letters of Credit**"), in form and substance which are satisfactory to replace the Vendor Letters of Credit; and

9.6.1.2 forthwith following the Closing, the Replacement Letters of Credit shall be delivered to the respective beneficiary or holder of the applicable Vendor Letters of Credit, together with a request of such beneficiary or holder, as the case may be, to return the applicable Vendor Letters of Credit to the Vendor for cancellation.

9.6.2 [redacted]

[redacted]

9.7 Change of Name

As soon as reasonably practicable, but no later than three months following the Closing Date, the Purchasers will cause the Purchased Entities and the Subsidiaries to remove the word "Brookfield" and "Great Lakes", and the logos and marks of the Vendor and any of its Affiliates or any word, expression or mark similar thereto or constituting an abbreviation or extension thereof (collectively the "**Vendor Marks**") from any of the documentation, correspondence or assets that are used, displayed, sent, presented or distributed by the Purchased Entities and the Subsidiaries or in connection with the Business. The Purchasers agree that after the Vendor Marks are removed, neither it nor the Purchased Entities and the Subsidiaries will at any time in the future use the words "Brookfield" or "Great Lakes", or the logos of the Vendor and any of its Affiliates in connection with its businesses and the Purchasers acknowledge that they and the Purchased Entities and the Subsidiaries shall have no rights whatsoever to use such Intellectual Property. At the request of the Vendor, the Purchasers will certify that they have complied with this Section 9.7 and provide such evidence as the Vendor may reasonably request to confirm such compliance.

9.8 Actions to Satisfy Closing Conditions

Without in any way limiting Section 9.9 or Section 9.10:

9.8.1 the Vendor shall take all such actions as are within its power to control, and use its Commercially Reasonable Efforts to cause other actions to be taken which are not within its power to control, to satisfy all of the conditions set forth in Section 8.1;

9.8.2 the Purchasers shall take all such actions as are within their power to control, and use their Commercially Reasonable Efforts to cause other actions to be taken which are not within their power to control, to satisfy all of the conditions set forth in Section 8.2;

9.8.3 the Parties shall file or deliver all applications, notices, reports, forms and requests required to obtain the consents, approvals, waivers and clearances required to consummate the transactions contemplated by this Agreement, including: (i) the Regulatory Approvals; and (ii) any notice or filing required by the Parties pursuant to the IESO market rules, and the Parties shall cooperate with each other and work jointly toward obtaining any such consents, approvals, waivers and clearances; and

9.8.4 the Parties shall, as soon as reasonably practical following the date hereof, take or cause to be taken all reasonable action and do or cause to be done all things reasonably necessary, proper or advisable under Applicable Laws to consummate the transactions contemplated hereby on the Closing Date.

9.9 Covenants of the Vendor Regarding the Regulatory Approvals

The Vendor shall and, where appropriate, shall cause the Purchased Entities and the Subsidiaries to:

9.9.1 use Commercially Reasonable Efforts to assist the Purchasers in obtaining the Regulatory Approvals;

9.9.2 except as prohibited by Applicable Laws, promptly notify the Purchasers of the occurrence of any of the following or any matter or event that has resulted, or is reasonably likely to result in any of the following: (i) any notice or other communication from any Person (other than a Governmental Authority) alleging that the consent of such Person is required in connection with this Agreement or any of the other transactions contemplated by this Agreement; and (ii) any Proceedings commenced or, to the Knowledge of the Vendor, threatened against, relating to or involving or otherwise affecting, the Vendor or any of its Affiliates that relate to the consummation of this Agreement or any of the other transactions contemplated by this Agreement; and

9.9.3 comply promptly with any requests or inquiries for additional information from Governmental Authorities, including to any interrogatories from intervenors, and participating in any required hearings and making all other filings required in connection with obtaining the Regulatory Approvals.

9.10 Covenants of the Purchasers Regarding the Regulatory Approvals

The Purchasers shall:

9.10.1 prepare and file all required applications and notifications for all Regulatory Approvals as promptly as practicable, and in any event within 30 Business Days after the date of this Agreement, and use best efforts (except for the Competition Act Clearance in which case the Purchasers shall use Commercially Reasonable Efforts) to obtain all Regulatory Approvals by the Outside Date and, in doing so, the Purchasers shall keep the Vendor reasonably informed as to the status of the proceedings related to obtaining the Regulatory Approvals, including by:

9.10.1.1 providing the Vendor with copies of all related applications and notifications to obtain the Regulatory Approvals in draft form;

9.10.1.2 permitting the Vendor to review, in draft form, and incorporating the Vendor's reasonable comments in, any communication to be given by a Purchaser to any Governmental Authority with respect to obtaining the Regulatory Approvals;

9.10.1.3 promptly furnishing the Vendor with copies of notices or other communications received by a Purchaser from, or given by a Purchaser to, any Governmental Authority with respect to the transactions contemplated by this Agreement;

9.10.1.4 not participating in any meeting or discussion related to the transactions contemplated by this Agreement, either in person or by telephone, with any Governmental Authority unless, to the extent not prohibited by such Governmental Authority, the Purchasers give the Vendor the opportunity to attend such meeting or discussion, provided that for greater certainty, nothing contained in this Agreement shall restrict or limit the Purchasers from making such commitments or providing such undertakings or assuming such obligations as it considers necessary or desirable in order to obtain the Regulatory Approvals; and

9.10.1.5 permitting the Vendor to intervene in any proceeding (either written or oral) conducted in respect of the OEB Approval;

9.10.2 not take any action that will have, or might reasonably be expected to have, the effect of: (i) materially delaying, impairing or impeding the granting of the Regulatory Approvals, including any subsequent acquisition; or (ii) altering, amending or causing the review of any aspect of any transmission rate order applicable to GLPT by the OEB;

9.10.3 use best efforts in respect of the OEB Approval and Commercially Reasonable Efforts in respect of the Competition Act Clearance to satisfy (or cause to be satisfied) the conditions precedent to its obligations hereunder set forth in Section 7.2.5 and to take, or cause to be taken, all other action and to do, or cause to be done, all other things necessary, proper or advisable under all Applicable Laws to complete the transactions contemplated by this Agreement and comply promptly with any requests or inquiries for additional information from Governmental Authorities, including to any interrogatories from intervenors, and participating in any required hearings and making all other filings required in connection with obtaining the Regulatory Approvals without limiting the foregoing, in seeking to obtain the OEB Approval, the Purchasers agree to accept any terms and conditions the OEB requires in connection with granting the OEB Approval that are not materially detrimental to the Business as currently conducted or materially detrimental to the value of the Purchased Securities;

9.10.4 use Commercially Reasonable Efforts to defend all lawsuits or other legal, regulatory or other Proceedings against a Purchaser or its Affiliates challenging or affecting this Agreement or the consummation of the transactions contemplated hereby; and

9.10.5 except as prohibited by Applicable Laws, promptly notify the Vendor of the occurrence of any of the following or any matter or event that has resulted, or is reasonably likely to result in any of the following: (i) any notice or other communication from any Person (other than a Governmental Authority) alleging that the consent of such Person is required in connection with this Agreement or any of the other transactions contemplated by this Agreement; and (ii) any Proceedings commenced or, to the Knowledge of the Purchasers, threatened against, relating to or involving or otherwise affecting, a Purchaser or its Affiliates that relate to the consummation of this Agreement or any of the other transactions contemplated by this Agreement.

9.11 Confidentiality

9.11.1 Purchasers acknowledge that the information being provided to it in connection with this Agreement and the consummation of the transactions contemplated hereby is subject to the terms of the confidentiality agreement entered into between the Parties (the "**Confidentiality Agreement**"), which shall survive the execution of this Agreement and the Closing. From and after the Closing, subject to Section 12.1, the confidentiality obligations of Purchasers under the Confidentiality Agreement shall terminate with respect to all Evaluation Materials (as defined in the Confidentiality Agreement) that relate exclusively to the Purchased Entities and Subsidiaries and not to any of the businesses or operations of Vendor or any of its Affiliates (other than the Purchased Entities and Subsidiaries).

9.11.2 Notwithstanding the foregoing, nothing in this Agreement or in the Confidentiality Agreement shall restrict the right of the Vendor, the Purchasers or any Purchased Entities or Subsidiaries to disclose any information to any Governmental Authority to the extent reasonably required in connection with seeking any Regulatory Approval.

9.11.3 Notwithstanding any other provision of this Agreement, the Purchasers and the Vendor shall be entitled to redact any information contained in draft and final submissions, filings or other written communications with the Commissioner or the OEB as necessary before sharing with the other Party to address reasonable privilege or confidentiality concerns, provided that the redacting Party must provide external legal counsel to the other Party non-redacted versions of drafts and final submissions, filings or other written communications on the basis that such non-redacted versions will not be shared by external legal counsel with its client (and pursuant to this Agreement the Purchasers and the Vendor hereby waive any rights to such redacted information).

9.12 Non-Solicit; No-Hire

The Vendor and BIP each agree not to, and to cause their respective subsidiaries not to, directly or indirectly:

9.12.1 for a period of 60 days following the Closing Date: (i) induce any individual who is an employee, contractor or full-time consultant of the Business, the Purchased Entities or the Subsidiaries to leave the Business, the Purchased Entities or the Subsidiaries or (ii) solicit for employment, employ or otherwise contract for the services of any individual who is employed or engaged, either as an employee, contractor or full-time consultant, by the Business, the Purchased Entities or the Subsidiaries; and

9.12.2 for a period of three years following the Closing Date: (i) induce any individual who is a senior management employee or who is otherwise engaged in a senior management role in the Business, the Purchased Entities or the Subsidiaries, or who is specified in writing by the Purchasers by way of written notice delivered to the Vendor within 60 days following the Closing Date (together, the "**Protected Employees**") to leave the Business, the Purchased Entities or the Subsidiaries; or (ii) solicit for employment, employ or otherwise contract for the services of any Protected Employee, provided that the restrictions set out in this Section 9.12.2 shall not apply to: (a) the act of issuing general advertisements or solicitations for employment, provided that the Vendor, BIP and their respective subsidiaries do not employ, hire or contract for the services of any Protected Employee as a result of those general advertisements or solicitations for employment; or (b) solicitation or hiring of any Protected Employee who has had their employment terminated by a Purchased Entity or a Subsidiary, as applicable.

9.13 Easement Documents

The Vendor shall use Commercially Reasonable Efforts to either: (i) obtain and register or cause its Affiliate to register, as the case may be, the Easement Documents on title to the properties referenced in Section 1.1.32 on or before Closing; or (ii) enter into a binding agreement on or before Closing with [redacted] pursuant to which such owner agrees to execute all Easement Documents once all necessary reference plans have been prepared and registered for no additional payment for such easement.

ARTICLE 10
INDEMNIFICATION

10.1 Indemnification by the Vendor

From and after the Closing Date, subject to Section 10.5, the Vendor shall indemnify and save each Purchaser Indemnified Party harmless from and against:

10.1.1 any Loss suffered or incurred by, imposed upon or asserted against any of them as a result of any breach of representation, warranty and/or covenant on the part of the Vendor contained in this Agreement;

10.1.2 any liability for Taxes of the Business, the Purchased Entities or the Subsidiaries in respect of any Straddle Period or any taxation year or other period ended on or prior to the Closing Date for which no adequate reserve has been provided and disclosed in the Financial Statements or the Estimated Working Capital Statement; and/or

10.1.3 any Loss suffered or incurred by, imposed on or asserted against any of them resulting from a change in the Tax Attributes of the Business, Purchased Entities or the Subsidiaries or any of their assets after the Closing as a result of any assessment or reassessment of the Vendor, the Business, the Purchased Entities or the Subsidiaries, received from a Tax authority in respect of the Straddle Period or a taxation year or other period that ended on or prior to the Closing Date or any portion of a taxation year or other period up to and including the Closing Date.

10.2 Indemnification by the Purchasers

From and after the Closing Date, subject to Section 10.5, each Purchaser shall indemnify and save each Vendor Indemnified Party harmless from and against:

10.2.1 any Loss suffered or incurred by, imposed upon or asserted against any of them as a result of any breach of representation, warranty and/or covenant on the part of either Purchaser contained in this Agreement; and/or

10.2.2 any Loss suffered or incurred by, imposed upon or asserted against any of them as a result of, in respect of, connected with, or arising out of, under or pursuant to any claim against, or draw made under, any or all of the Vendor Letters of Credit after the Closing.

10.3 Notice of Claim

An Indemnified Party shall promptly give notice to the Indemnitor of any claim for indemnification pursuant to Section 10.1 or Section 10.2 (a "**Claim**", which term shall include more than one Claim). Such notice shall specify whether the Claim arises as a result of a claim by a Person (other than a Party or any Affiliate thereof or another Indemnified Party) against the Indemnified Party (a "**Third Party Claim**") or whether the Claim does not so arise (a "**Direct Claim**"), and shall also specify with reasonable particularity (to the extent that the information is available):

10.3.1 the factual basis for the Claim; and

10.3.2 the amount of the Claim, or, if an amount is not then determinable, an approximate and reasonable estimate of the likely amount of the Claim.

The failure to promptly provide such notice will not relieve the Indemnitor of any obligation to indemnify the Indemnified Party, except to the extent that such failure materially prejudices the Indemnitor.

10.4 Procedure for Indemnification

10.4.1 <u>Direct Claims</u>

With respect to Direct Claims, following receipt of notice from the Indemnified Party of a Claim, the Indemnitor shall have 30 days to make such investigation of the Claim as the Indemnitor considers necessary or desirable. For the purpose of such investigation, the Indemnified Party shall make available to the Indemnitor and its authorized representatives the information relied upon by the Indemnified Party to substantiate the Claim. If the Indemnified Party and the Indemnitor agree at or prior to the expiration of such 30 day period (or any mutually agreed upon extension thereof) to the validity and amount of such Claim, the Indemnitor shall immediately pay to the Indemnified Party the full agreed upon amount of the Claim.

10.4.2 <u>Third Party Claims</u>

Subject to Section 10.4.3:

10.4.2.1 With respect to any Third Party Claim, the Indemnitor shall have the right, at its own expense, to participate in or assume control of the negotiation, settlement or defence of such Third Party Claim and, in such event, the Indemnitor shall reimburse the Indemnified Party for all of the Indemnified Party's out-of-pocket expenses as a result of such participation or assumption. If the Indemnitor elects to assume such control, the Indemnified Party shall cooperate with the Indemnitor, shall have the right to participate in the negotiation, settlement or defence of such Third Party Claim at its own expense and shall have the right to disagree on reasonable grounds with the selection and retention of counsel, in which case counsel reasonably satisfactory to the Indemnitor and the Indemnified Party shall be retained by the Indemnitor.

10.4.2.2 Any Indemnified Party will have the right to employ separate counsel in any Third Party Claim and/or participate in the defence thereof, but the fees and expenses of such counsel will not be included as part of any Losses incurred by the Indemnified Party unless: (i) such Indemnified Party has received an opinion of counsel, reasonably acceptable to the Indemnitor, to the effect that the interests of the Indemnified Party and the Indemnitor with respect to the Third Party Claim are sufficiently adverse to prohibit the representation by the same counsel of both the Indemnitor and the Indemnified Party under applicable ethical rules, or (ii) the employment of such counsel at the expense of the Indemnitor has been specifically authorized by the Indemnitor.

10.4.2.3 If the Indemnitor, having elected to assume control as contemplated in Section 10.4.2.1 thereafter fails to defend any such Third Party Claim within a reasonable time, the Indemnified Party shall be entitled to assume such control and the Indemnitor shall be bound by the results obtained by the Indemnified Party with respect to such Third Party Claim. In addition, the Indemnitor shall reimburse the Indemnified Party's out-of-pocket expenses, including expenses of counsel, as a result of such assumption.

10.4.3 <u>Tax Related Matters</u>

10.4.3.1 After the Closing Date, the Vendor shall control the conduct, through counsel of its own choosing, of any audit, claim for refund, or Proceeding involving any of the Purchased Entities or any of the Subsidiaries in respect of any Liability or refund in respect of Taxes relating to the Pre-Closing Tax Period or any Straddle Period (any such audit, claim for refund, or Proceeding referred to herein as a "**Contest**").

10.4.3.2 The Vendor and the Purchasers agree to furnish or cause to be furnished to each other, upon request, as promptly as practicable, such information (including access to books and records) and assistance relating to the Purchased Entities and the Subsidiaries as is reasonably requested for determining a Liability in respect of Taxes or a right to a refund of Taxes, and the preparation, prosecution, defense or conduct of any Contest. The Vendor and the Purchasers shall reasonably cooperate with each other in the conduct of any Contest and each Party shall execute and deliver such powers of attorney and other documents as are necessary to carry out the intent of this Section 10.4.3.2.

10.4.3.3 The Vendor and the Purchasers shall, and shall cause each of the Purchased Entities and each of the Subsidiaries to: (i) use best efforts to properly retain and maintain the Tax and accounting records of the Purchased Entities and the Subsidiaries that relate to the Pre-Closing Tax Periods and the Straddle Period for seven years following the Closing or if any of the Purchased Entities or any Subsidiary has been assessed Taxes, for such longer period as is reasonably necessary to contest such assessments, and shall thereafter provide the Vendor with written notice prior to any destruction, abandonment or disposition of all or any portions of such records; (ii) transfer such records to the Vendor upon its written request prior to any such destruction, abandonment or disposition; and (iii) allow the Vendor and its representatives, at times and dates reasonably and mutually acceptable to the Parties, to from time to time inspect and review such records as the Vendor may deem necessary or appropriate; provided, however, that in all cases, such activities are to be conducted by the Vendor and its representatives during normal business hours.

10.5 Additional Rules and Procedures

The obligation of an Indemnitor to indemnify the Indemnified Party in respect of Claims shall also be subject to the following:

10.5.1 Any Claim arising as a result of a breach of a representation or warranty contained in this Agreement shall be made not later than the date on which, pursuant to Section 10.10, such representation or warranty terminated.

10.5.2 The Vendor's obligation to indemnify the Purchaser Indemnified Parties pursuant to Section 10.1 shall apply only to the extent that the Claims of the Purchaser Indemnified Parties pursuant to Section 10.1, in the aggregate, exceed an amount equal to one percent (1.0%) of the Purchase Price. For clarity, if such Claims of the Purchaser Indemnified Parties exceed, in the aggregate, an amount equal to one percent (1.0%) of the Purchase Price, the Vendor shall be obligated to indemnify the Purchaser Indemnified Parties only in respect of the portion of such Claims that exceed an amount equal to one half percent (0.5%) of the Purchase Price.

10.5.3 Subject to Section 10.5.5, the Vendor's obligation to indemnify the Purchaser Indemnified Parties pursuant to Section 10.1 in respect of breaches of representations and warranties of the Vendor contained in this Agreement (other than the Fundamental Representations and Warranties) shall terminate if and when the Vendor has indemnified the Purchaser Indemnified Parties for Losses in respect thereof, in aggregate, equal to the Vendor Liability Cap. Subject to Sections 10.5.4 and 10.5.5, if the Vendor's indemnification obligations in respect of breaches of representations and warranties of the Vendor contained in this Agreement (other than the Fundamental Representations and Warranties) have been terminated under this Section 10.5.3, a Purchaser Indemnified Party shall no longer be entitled to seek compensation or other monetary relief or damages from the Vendor for any matter in respect of which such Purchaser Indemnified Party could have made a Claim in respect of breaches of representations and warranties of the Vendor contained in this

Agreement (other than the Fundamental Representations and Warranties) under Section 10.1 but for this Section 10.5.3.

10.5.4 Section 10.5.3 shall not apply to any Claim by a Purchaser Indemnified Party in respect of breaches of the representations and warranties of the Vendor contained in Section 4.1, Section 4.2, Section 4.3.1, Section 4.4, Section 5.1, Section 5.2, Section 5.3, Section 5.4 and/or Section 5.5 (collectively, the "**Fundamental Representations and Warranties**"). Subject to Section 10.5.5, the Vendor's obligation to indemnify the Purchaser Indemnified Parties pursuant to Section 10.1 in respect of breaches of the Fundamental Representations and Warranties shall terminate if and when the Vendor has indemnified the Purchaser Indemnified Parties for Losses in respect thereof, in aggregate, equal to the Purchase Price. If the Vendor's indemnification obligations have been terminated under this Section 10.5.4, a Purchaser Indemnified Party shall no longer be entitled to seek compensation or other monetary relief or damages from the Vendor for any matter in respect of which such Purchaser Indemnified Party could have made a Claim in respect of breaches of the Fundamental Representations and Warranties under Section 10.1 but for this Section 10.5.4.

10.5.5 Notwithstanding anything to the contrary in this Agreement:

10.5.5.1 except as set forth in Section 10.5.5.4, the Vendor's liability to the Purchaser Indemnified Parties for Losses in respect of breaches of representations and warranties of the Vendor contained in this Agreement shall in no circumstances exceed, in aggregate, the Purchase Price;

10.5.5.2 each Party waives any right to recover, and no Indemnified Party shall be entitled to recover, from another Party (including an Indemnitor) for any Losses, any amount in excess of the actual compensatory damages, court costs and reasonable lawyers' and other advisor fees suffered by such Indemnified Party;

10.5.5.3 each Party waives any right to recover, and no Indemnified Party shall be entitled to recover, punitive, incidental, indirect, special, exemplary and consequential damages, and economic loss and damages in respect of loss of profits and loss of opportunity arising in connection with or respect to this Agreement; and

10.5.5.4 the limitations set forth in Section 10.5.2, Section 10.5.3, Section 10.5.4 and Section 10.5.6 shall not apply to any Claims based on intentional misrepresentation or fraud by the Vendor or any Person acting for or on behalf of the Vendor,

provided that the provisions of Section 10.5.5.2 and Section 10.5.5.3 shall not apply to indemnification for a Third Party Claim.

10.5.6 With respect to any Claim as to which an Indemnified Party may be entitled to indemnification under Section 10.1, an Indemnitor shall not be liable for any individual or series of related Losses which do not exceed $100,000 (and any of which Losses, for greater certainty, shall not be counted towards the limits set forth in Section 10.5.2 and Section 10.5.3, Section 10.5.4 and Section 10.5.5.1), provided that, and notwithstanding the foregoing, this Section 10.5.6 shall not apply to Claims with respect to breaches of Article 2, Section 6.10 or Section 9.4.

10.5.7 In the event that any Third Party Claim is of a nature such that the Indemnified Party is required by Applicable Law to make a payment to any Person that is not an Affiliate of the Indemnified Party (a "**Third Party**") with respect to such Third Party Claim before the completion of settlement negotiations or related legal Proceedings, the Indemnified Party may make such payment and the Indemnitor shall, forthwith after demand by the Indemnified Party, reimburse the Indemnified Party for any such payment. If the amount of any liability of the Indemnified Party under the Third Party Claim in respect of which such a payment was made, as finally determined, is less than the amount which was paid by the Indemnitor to the Indemnified Party, the Indemnified Party shall, forthwith after receipt of the difference from the Third Party, pay the amount of such difference to the Indemnitor.

10.5.8 Except in the circumstances contemplated by Section 10.4.2.3 and Section 10.5.7 and whether or not the Indemnitor assumes control of the negotiation, settlement or defence of any Third Party Claim, the Indemnified Party shall not negotiate, settle, compromise or pay any Third Party Claim except with the prior written consent of the Indemnitor (which consent shall not be unreasonably withheld, delayed or conditioned). The Indemnitor shall not settle or compromise any Third Party Claim except with the prior written consent of the Indemnified Party (which consent shall not be unreasonably withheld, delayed or conditioned) if such settlement or compromise involves an admission of guilt or liability on the part of the Indemnified Party or would lead to liability or create any financial or other obligation on the part of the Indemnified Party for which the Indemnified Party is not entitled to indemnification under this Agreement.

10.5.9 The Indemnified Party shall not permit any right of appeal in respect of any Third Party Claim to terminate without giving the Indemnitor notice thereof and an opportunity to contest such Third Party Claim.

10.5.10 The Indemnified Party and the Indemnitor shall cooperate fully with each other with respect to Third Party Claims, shall keep each other fully advised with respect thereto (including supplying copies of all relevant documentation promptly as it becomes available) and shall each designate a senior officer who will keep informed about and be prepared to discuss the Third Party Claim with his counterpart and with counsel at all reasonable times.

10.5.11 If the amount of any Loss, at any time subsequent to the making of an indemnity payment in respect thereof, is reduced by an Indemnified Party by recovery, settlement or otherwise under or pursuant to any insurance coverage, or pursuant to any claim, recovery, settlement or payment by, from or against any Person (other than an Indemnitor), the amount of such reduction, together with any interest earned on such amount, if applicable, less any deductibles, costs or expenses incurred in connection therewith, shall be promptly paid to by the Indemnified Party to the Indemnitor.

10.5.12 Except as otherwise required by Applicable Law, all payments made by the Vendor pursuant to this Article 10 shall be treated as a decrease to the Purchase Price and all payments made by the Purchasers pursuant to this Article 10 shall be treated as an increase to the Purchase Price.

10.5.13 Notwithstanding any provision of this Article 10, a Purchaser Indemnified Party shall not be entitled to recover from the Vendor for any Losses that are included as Current Liabilities in the Final Working Capital.

10.6 OEB Loss Recovery

10.6.1 Notwithstanding any provision of this Article 10, before seeking recovery from the Vendor in respect of a Claim pursuant to this Article 10, the Purchasers shall first make Commercially Reasonable Efforts to seek, or to cause their Affiliates or GLPT, as applicable, to make Commercially Reasonable Efforts to seek, relief from the OEB to recover any Losses associated with that Claim through any applicable regulatory means including an application to the OEB, including a rate recovery application and/or an application for a variance or deferral account, provided however that the Purchasers shall only be required to pursue, or cause their Affiliates or GLPT to pursue, as applicable, such an application as a pre-condition to recovery where it is reasonable to expect that Losses associated with such an application would be recoverable within sixty (60) months of commencing the application, and provided further that in no event shall the Purchasers, their Affiliates or GLPT be required to file an application for re-basing in order to obtain such relief.

10.6.2 Where an application to the OEB to recover any Losses associated with a Claim would be reasonable in accordance with Section 10.6.1, the Purchasers shall, or shall cause their Affiliates or GLPT, as applicable, to, as soon as would be commercially reasonable after the delivery by the applicable Purchaser Indemnified Party of the notice in respect of the Claim, make Commercially Reasonable Efforts to apply to the OEB for recovery of any Losses incurred or to be incurred by the applicable Purchaser Indemnified Party in connection with the Claim (the "**OEB Loss Recovery Application**"), including without limitation the costs associated with making such OEB Loss Recovery Application; provided that the Purchasers shall, or shall cause their Affiliates or GLPT, as applicable, to, prior to filing the OEB Loss Recovery Application with the OEB, deliver the OEB Loss Recovery Application to the Vendor and allow the Vendor at least thirty (30) days to review and comment on the OEB Loss Recovery Application; provided further that the Purchasers shall, or shall cause their Affiliates or GLPT, as applicable, to, consider and use Commercially Reasonable Efforts to incorporate the comments of the Vendor into the OEB Loss Recovery Application prior to filing the OEB Loss Recovery Application with the OEB.

10.6.3 The Purchasers in consultation with the Vendor and acting reasonably may appeal, or cause their Affiliates or GLPT, as applicable, to appeal, any decision of the OEB or seek a review of the decision relating to an OEB Loss Recovery Application, and further appeal any appellate decision of a court of competent jurisdiction in respect of the OEB Loss Recovery Application, until a final determination of the OEB Loss Recovery Application has been made and all periods in which an application could be filed by any Person for the judicial review or appeal of such final determination have expired (a "**Final Determination**").

10.6.4 Upon obtaining a Final Determination of the OEB Loss Recovery Application, the Purchasers shall, or shall cause their Affiliates or GLPT, as applicable, to promptly deliver a notice to the Vendor setting out: (i) the Claim to which the notice relates; (ii) the final outcome of the OEB Loss Recovery Application and any reviews or appeals thereof; (iii) any additional facts or circumstances pertaining to the Claim which were not set out in the original notice of the Claim; and (iv) the amount of the Losses arising out of the Claim, including without limitation the costs associated with the OEB Loss Recovery Application, if known.

10.6.5 The Vendor's liability for Losses in respect of a Claim for which a Final Determination has been received shall be reduced by the amount of any costs recovered or recoverable by the applicable Purchaser Indemnified Party or GLPT pursuant to such Final Determination.

10.6.6 The indemnification liability of the Vendor to the applicable Purchaser Indemnified Party under this Article 10 in respect of a Claim that is subject to the OEB Loss Recovery Application procedure set out in this Section 10.6 shall, for greater certainty, include any lawyers', experts' and consultants' fees and expenses incurred by the applicable Purchaser Indemnified Party on the OEB Loss Recovery Application.

10.6.7 Upon obtaining a Final Determination of the OEB Loss Recovery Application, the Vendor shall immediately pay to the applicable Purchaser Indemnified Party the full amount, if any, by which the Losses arising out of the original Claim required to be indemnified by the Vendor pursuant to, and in accordance with, this Article 10, exceed the value of the Final Determination of the OEB Loss Recovery Application.

10.7 Indemnification Claims

The Parties agree that Article 10 sets out the sole and exclusive manner by which the Indemnified Party may seek monetary compensation from the Indemnitor for any matter in respect of which the Indemnified Party may make a Claim under Section 10.1 or Section 10.2, including, for greater certainty, any matter that could be made a Claim under Section 10.1 or Section 10.2, but for Section 10.5.2, Section 10.5.3, Section 10.5.4, and/or Section 10.5.5.

10.8 Trust

It is the intention of each Purchaser to constitute the Vendor as trustee for the Vendor Indemnified Parties that are not Party to this Agreement of the covenants of each Purchaser contained in Article 10 and the Vendor agrees to accept such trust and to hold and enforce such covenants on behalf of each such Person. It is the intention of the Vendor to constitute each Purchaser as a trustee for the Purchaser Indemnified Parties that are not Party to this Agreement of the covenants of the Vendor contained in Article 10 and each Purchaser agrees to accept such trust and to hold and enforce such covenants on behalf of each such Person.

10.9 Set-Off

10.9.1 A Party (the "**first Party**" for the purposes of this Section 10.9) may set off any amount owing from the other Party or any of its Affiliates (collectively, the "**second Party**" for the purposes of this Section 10.9) to the first Party under this Agreement or any other agreement related to the transactions contemplated by this Agreement against any amounts due and payable by the first Party to the second Party under this Agreement.

10.9.2 This Section 10.9 shall be without prejudice and in addition to any right of set-off, combination of accounts, lien or other right to which either Party is at any time otherwise entitled (whether by operation of Applicable Laws, agreement or otherwise), including general principles of common law or equity.

10.10 Survival of Covenants, Representations and Warranties

10.10.1 The representations and warranties given or made by a Party in this Agreement or in any certificate delivered pursuant to this Agreement shall survive the Closing and continue in full force and effect for a period of 18 months after the Closing Date and shall thereafter terminate and be of no further force or effect, provided that, and notwithstanding the foregoing, the Fundamental Representations and Warranties shall survive Closing and continue indefinitely, the representations and warranties of the Purchasers set out in Section 6.10 shall survive Closing for a period of three years after the Closing Date and the representations and warranties of the Vendor set out in Section 4.3.2 and Section 5.16 shall survive the Closing and terminate 90 days after the relevant Governmental Authorities shall no longer be entitled to assess or reassess liability for Taxes against the Vendor (in respect of its ownership of the Purchased Entities), the Purchased Entities or the Subsidiaries, as applicable, for that particular period, having regard, without limitation, to any waivers given by the Vendor (in respect of its ownership of the Purchased Entities), the Purchased Entities or the Subsidiaries, as applicable, in respect of any taxation year.

10.10.2 No Claim for breach of representation or warranty shall be valid unless the Party against whom such Claim is made has been given notice thereof before the date on which the applicable representation or warranty shall have terminated in accordance with Section 10.10.1. No Party has any obligation or liability with respect to any representation or warranty made by such Party in this Agreement or the certificates to be delivered pursuant to this Agreement, as the case may be, after the end of the survival period specified in Section 10.10.1, except for Claims relating to representations and warranties of which the Party has provided notice to the other Party pursuant to Article 10 prior to the end of the applicable survival period.

10.10.3 Subject to Sections 10.10.1 and 10.10.2, the covenants of the Parties set forth in this Agreement, including the indemnification obligations pursuant to this Article 10, shall survive the Closing indefinitely, unless any such covenant by its terms expires on or before Closing, and each Party shall be entitled to the full performance thereof by the other Party without limitation as to time or amount (except as specifically set forth in this Agreement).

10.11 Specific Performance

Each Party shall be entitled to apply to a court for equitable relief, including injunction and specific performance, in the event of any breach or anticipatory breach by the other Party of the provisions of this Agreement or in the event of any fraud of the other Party, in addition to any other remedies available to the undersigned at Applicable Law, and the Parties acknowledge and agree that an award of damages may not be an effective or adequate remedy in the event of a breach of this Agreement or in the event of any fraud of the other Party.

ARTICLE 11
TERMINATION

11.1 Termination Events

This Agreement may, by notice in writing given prior to the Closing, be terminated:

11.1.1 by mutual written consent of the Vendor and the Purchasers; and

11.1.2 by a Party (the "**first Party**" for the purposes of this Section 11.1) giving notice to the other Party if the Closing has not occurred on or before the Outside Date unless the Closing has not occurred by the Outside Date because there has been a breach of this Agreement by the first Party.

11.2 Effect of Termination

11.2.1 Each Party's right of termination under this Article 11 is in addition to any other rights it may have under this Agreement or otherwise, and the exercise of a right of termination will not be an election of remedies. Nothing in this Article 11 limits or affects any other rights or causes of action either Party may have with respect to the representations, warranties, covenants and indemnities in its favour contained in this Agreement. If a Party waives compliance with any of the conditions, obligations or covenants contained in this Agreement, the waiver will be without prejudice to any of its rights of termination in the event of non-fulfillment, non-observance or non-performance of any other condition, obligation or covenant in whole or in part.

11.2.2 If this Agreement is terminated pursuant to Section 11.1, all obligations of the Parties under this Agreement will terminate, except that:

11.2.2.1 if this Agreement is terminated by the Vendor because of a breach of a representation, warranty and/or covenant contained in this Agreement by a Purchaser or because a condition for the benefit of the Vendor has not been satisfied because a Purchaser has failed to perform any of its obligations or covenants under this Agreement, the Vendor's right to pursue all legal remedies with respect thereto, including pursuant to Article 10, will survive such termination and continue in full force and effect;

11.2.2.2 if this Agreement is terminated by the Purchasers because of a breach of a representation, warranty and/or covenant contained in this Agreement by the Vendor or because a condition for the benefit of the Purchasers has not been satisfied because the Vendor has failed to perform any of its obligations or covenants under this Agreement, the Purchasers' right to pursue all legal remedies with respect thereto, including pursuant to Article 10, will survive such termination and continue in full force and effect; and

11.2.2.3 Article 1, Section 9.11, Section 11.2, Section 12.1, and Section 12.2 will survive such termination and continue in full force and effect.

ARTICLE 12
GENERAL MATTERS

12.1 Public Notices

No press release or other announcement concerning the transactions contemplated by this Agreement shall be made by a Party without the prior written consent of the other Party (such consent not to be unreasonably withheld, delayed or conditioned), provided, however, that a Party may, without such consent, make such disclosure if the same is required by Applicable Laws or any stock exchange on which any of the securities of such Party or any of its Affiliates are listed or by any securities commission or other similar Governmental Authority having jurisdiction over such Party or any of its Affiliates, and if such disclosure is required, the Party making the disclosure shall use reasonable efforts to give prior written notice to the other Party, and if such prior notice is not possible, to give such notice immediately following the making of such disclosure.

12.2 Expenses

Each of the Vendor and the Purchasers shall be responsible for the expenses (including fees and expenses of legal advisers, accountants and other professional advisers) incurred by them, respectively, in connection with the negotiation and settlement of this Agreement and the completion of the transaction contemplated hereby, except that any filing fees, costs and expenses payable in connection with the Regulatory Approvals shall be borne by the Purchasers.

12.3 Assignment

This Agreement shall be binding upon, and shall inure to the benefit of, and shall be enforceable by, the Parties and their respective successors and permitted assigns. No Party may assign its rights or benefits under this Agreement without the prior consent of the other Party.

12.4 Legal Representation

Each Purchaser hereby acknowledges and agrees, on its own behalf and on behalf of its directors, members, partners, officers, employees and Affiliates (including, after the Closing, the Purchased Entities and the Subsidiaries), and each of their successors and assigns (all such parties, collectively, the "**Waiving Parties**"), that: (i) Torys LLP may represent (a) the Vendor and its Affiliates, other than the Purchased Entities and the Subsidiaries, (individually and collectively, the "**Vendor Group**"), and (b) the Purchased Entities and the Subsidiaries in connection with the negotiation, preparation, execution and delivery of this Agreement and the ancillary agreements related thereto and the consummation of the transactions contemplated herein and therein (such representation, the "**Current Representation**"); and (ii) following the Closing, Torys LLP (or any successor) may represent the Vendor Group and any director, member, partner, officer, employee and Affiliate of the Vendor Group, in each case, in connection with any dispute, litigation, claim, proceeding or obligation arising out of or relating to this Agreement or any ancillary agreement related hereto and/or the consummation of the transactions contemplated herein and therein (any such representation, the "**Post-Closing Representation**") notwithstanding the Current Representation, and each Purchaser, on behalf of itself and the Waiving Parties, hereby consents thereto and irrevocably waives (and will not assert) any conflict of interest or any objection arising therefrom or relating thereto. Each Purchaser, on behalf of itself and the Waiving Parties, hereby irrevocably acknowledges and agrees that all communications between the Vendor Group, the Purchased Entities, and/or the Subsidiaries, on the one hand, and their counsel, including Torys LLP, on the other hand, made in connection with the Current Representation are privileged communications between the Vendor Group, the Purchased Entities, and the Subsidiaries and such counsel and none of the Purchasers, the Purchased Entities, and the Subsidiaries or any Person purporting to act on behalf of or through the Purchasers or the Purchased Entities or the Subsidiaries or any of the Waiving Parties, will seek to obtain the same or waive any such privilege by any process. From and after the Closing, each Purchaser, on behalf of itself and the Waiving Parties, waives and will not assert any solicitor-client privilege with respect to any communication between Torys LLP and the Purchased Entities and/or the Subsidiaries or any Person in the Vendor Group occurring during the Current Representation in connection with any Post-Closing Representation. Further, in the event that a dispute arises after the Closing between the Purchasers and/or the Purchased Entities and/or the Subsidiaries, on the one hand, and a Person other than the Vendor Group, on the other hand, the Purchased Entities and the Subsidiaries may assert solicitor-client privilege to prevent disclosure of confidential communications by Torys LLP (or any successors) or the Vendor Group to such third party; provided, however, that the Purchased Entities and the Subsidiaries may not waive such privilege without the prior written consent of the Vendor (which consent shall not be unreasonably withheld, conditioned or delayed).

12.5 Notices

Any notice or other communication required or permitted to be given hereunder shall be in writing and shall be given by facsimile or other means of electronic communication or by hand-delivery as hereinafter provided. Any such notice or other communication, if sent by facsimile or other means of electronic communication, shall be deemed to have been received on the Business Day following the sending, or if delivered by hand shall be deemed to have been received at the time it is delivered to the applicable address noted below either to the individual designated below or to an individual at such address having apparent authority to accept deliveries on behalf of the addressee. Notice of change of address shall also be governed by this Section 12.5. Notices and other communications shall be addressed as follows:

12.5.1 if to the Vendor:

Brookfield Infrastructure Holdings (Canada) Inc.
Brookfield Place, Suite 300
181 Bay Street
Toronto, ON M5J 2T3

Attention: James Rickert
Fax: (416) 369-2708
Email: James.Rickert@brookfield.com

with a copy (that does not constitute notice) to:

Torys LLP
Suite 3000
79 Wellington Street West
Toronto, ON M5K 1N2

Attention: Rima Ramchandani
Fax: (416) 865-7666
Email: rramchandani@torys.com

12.5.2 If to BIP:

Brookfield Infrastructure Partners L.P.
73 Front Street
5th Floor
Hamilton, Bermuda HM 12

Attention: Jane Sheere
Fax: (441) 296-4475
Email: jane.sheere@brookfield.com

with a copy (that does not constitute notice) to:

Torys LLP
Suite 3000
79 Wellington Street West
Toronto, ON M5K 1N2

Attention: Rima Ramchandani
Fax: (416) 865-7666
Email: rramchandani@torys.com

12.5.3 if to the Purchasers:

Hydro One Inc. or
1937672 Ontario Inc.
483 Bay Street, 8th Floor
South Tower
Toronto, ON M5G 2P5

Attention: Rhonda Wise, Assistant General Counsel
Fax: 416 351-6301
Email: wiser@hydroone.com

with a copy (that does not constitute notice) to:

Osler, Hoskin & Harcourt LLP
100 King Street West
1 First Canadian Place
Suite 6200, P.O. Box 50
Toronto ON M5X 1B8

Attention:	Michael Innes
Fax:	416-862-6666
Email:	minnes@osler.com

The failure to send or deliver a copy of a notice to the Purchasers' counsel or the Vendor's counsel, as the case may be, shall not invalidate any notice given under this Section 12.5.

12.6 Time of Essence

Time is of the essence of this Agreement.

12.7 Submission to Jurisdiction

The Parties hereby irrevocably and unconditionally consent to and submit to the exclusive jurisdiction of the courts of the Province of Ontario for any Proceeding arising out of or relating to this Agreement or the matters contemplated hereby (and the Parties agree not to commence any Proceeding relating thereto except in such courts) and the Parties further agree that service of any process, summons, notice or document by registered mail to the applicable Party's address set forth in Section 12.5 shall be effective service of process for any Proceeding brought against that Party in such court. The Parties hereby irrevocably and unconditionally waive any objection to the laying of venue of any Proceeding arising out of this Agreement or the matters contemplated hereby in the courts of the Province of Ontario and hereby further irrevocably and unconditionally waive and agree not to plead or claim in any such court that any such Proceeding so brought has been brought in an inconvenient forum.

12.8 Joint and Several Liability

Each Purchaser covenants and agrees that it shall be jointly and severally liable to the Vendor with respect to all of the obligations of either of the Purchasers under this Agreement.

12.9 BIP Guarantee

BIP agrees that it will cause the Vendor to comply with all of its obligations under this Agreement in accordance with the terms of this Agreement, and agrees that it will be liable to the Purchasers to the extent of a failure by the Vendor to comply with its obligations under this Agreement in accordance with the terms of this Agreement.

12.10 Further Assurances

Each of the Parties shall promptly do, make, execute, deliver, or cause to be done, made, executed or delivered, all such further acts, documents and things as the other Party hereto may reasonably require from time to time for the purpose of giving effect to this Agreement and shall use reasonable efforts and take all such steps as may be reasonably within its power to implement to their full extent the provisions of this Agreement.

12.11 Counterparts

This Agreement may be signed in counterparts and each such counterpart shall constitute an original document and such counterparts, taken together, shall constitute one and the same instrument.

12.12 Electronic Execution

The exchange of copies of this Agreement and of signature pages by facsimile or other electronic transmission shall constitute effective execution and delivery of this Agreement and may be used in lieu of the original Agreement for all purposes. Signatures of the Parties transmitted by facsimile or other electronic means shall be deemed to be their original signatures for all purposes.

[Remainder of this page intentionally left blank.]

IN WITNESS WHEREOF the parties hereto have executed this Agreement.

HYDRO ONE INC.

by:

Name: Michael Vels
Title: Chief Financial Officer

1937672 ONTARIO INC.

by:

Name: Michael Vels
Title:

BROOKFIELD INFRASTRUCTURE HOLDINGS (CANADA) INC.

by: ______________________________
Name:
Title:

BROOKFIELD INFRASTRUCTURE PARTNERS L.P., by its general partner Brookfield Infrastructure Partners Limited

by: ______________________________
Name:
Title:

IN WITNESS WHEREOF the parties hereto have executed this Agreement.

HYDRO ONE INC.

by: ____________________

Name:

Title:

by: ____________________

Name:

Title:

1937672 ONTARIO INC.

by: ____________________

Name:

Title:

by: ____________________

Name:

Title:

BROOKFIELD INFRASTRUCTURE HOLDINGS (CANADA) INC.

by: ____________________

Name: James Rickert

Title: Vice President & Secretary

BROOKFIELD INFRASTRUCTURE PARTNERS L.P., by its general partner Brookfield Infrastructure Partners Limited

by: ____________________

Name: Gregory E. A. Morrison

Title: President

[Signature Page to Share Purchase Agreement]

EXHIBIT A

FORM OF RELEASE TO DIRECTORS AND OFFICERS

<u>RELEASE</u>

TO: ● *{insert name of director/officer}*

In consideration of the sum of $1.00 and for other good and valuable consideration, the receipt and sufficiency of which are hereby irrevocably acknowledged, the undersigned (the "**Releasor**", which term includes its successors and assigns) hereby remises, releases and forever discharges ● *{insert name of director/officer}*, as an individual and in **[his/her]** capacity as a **[director and/or officer]** of the undersigned, and **[his/her]** heirs, executors, estate trustees, personal representatives and administrators (collectively, the "**Releasees**") of and from any and all actions, causes of action, suits, debts, dues, accounts, bonds, covenants, contracts, claims, liabilities, obligations, complaints and demands whatsoever, whether known or unknown, suspected or unsuspected, and whether arising at law or in equity, contingent or otherwise (collectively, the "**claims**"), which the Releasor ever had, now has or can, shall or may hereafter have against the Releasees, or any of them, for or by reason of or in any way arising out of ● {insert name of director/officer} having acted as an **[officer and/or director]** of the undersigned (all of the foregoing being the "**Released Subject Matter**").

It is further agreed that for the consideration aforesaid, the Releasor shall not make any claim or commence or maintain any action or proceeding against any person in relation to or in any way arising out of the Released Subject Matter, in which any claim could arise against the Releasees or any of them for contribution or indemnity or for other relief over.

The undersigned acknowledges having had an adequate opportunity to read and consider this release and to obtain such advice in regard to it as the undersigned considered advisable.

If any provision of this Release or any part of any provision of this Release is held under any circumstances to be invalid or unenforceable in any jurisdiction, then: (i) such provision or part thereof shall, with respect to such circumstances and in such jurisdiction, be deemed amended to conform to applicable laws so as to be valid and enforceable to the fullest possible extent, (ii) the invalidity or unenforceability of such provision or part thereof under such circumstances and in such jurisdiction shall not affect the validity or enforceability of such provision or part thereof under any other circumstances or in any other jurisdiction, and (iii) such invalidity or unenforceability of such provision or part thereof shall not affect the validity or enforceability of the remainder of such provision or the validity or enforceability of any other provision of this Release. Each provision of this Release is separable from every other provision of this Release, and each provision of this Release is separable from every other part of such provision.

This Release shall be governed by, enforced, construed and interpreted in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

DATED this ______ day of ____________________, 2016.

● *{insert name of the applicable Purchased Entity and/or applicable Subsidiary}*

By: ____________________________________

Name:

Title:

EXHIBIT B

FORM OF RELEASE TO THE PURCHASED ENTITIES AND SUBSIDIARIES

RELEASE

Reference is made to a purchase agreement (the "**Agreement**") dated January 28, 2016 among Brookfield Infrastructure Holdings (Canada) Inc., Brookfield Infrastructure Partners L.P., Hydro One Inc. and 1937672 Ontario Inc.

In consideration of the sum of $1.00 of lawful money of Canada and other good and valuable consideration, the receipt and sufficiency of which are hereby irrevocably acknowledged, the undersigned, being an **[officer and/or director]** of ● *{insert name of the applicable Purchased Entity and/or applicable Subsidiary}*, on **[his/her]** own behalf and on behalf of **[his/her]** heirs, executors, estate trustees, personal representatives and administrators (herein referred to collectively as the "**Releasor**", which term includes any one or more of them) hereby remises, releases and forever discharges: (i) ●*{insert name of the applicable Purchased Entity and/or applicable Subsidiary}*, and (ii) its present and former officers, directors, servants, agents and employees (other than the undersigned) and their respective predecessors, successors, heirs, executors, estate trustees, personal representatives and administrators and assigns (collectively, the "**Releasees**") of and from any and all actions, causes of action, suits, debts, dues, accounts, bonds, covenants, contracts, claims, liabilities, obligations, complaints and demands whatsoever, whether known or unknown, suspected or unsuspected, and whether arising at law or in equity, contingent or otherwise (collectively, the "**claims**"), which the Releasor ever had, now has or can, shall or may hereafter have for or by reason of or in any way arising out of the undersigned having acted as an **[officer and/or director]** of ● {insert name of the applicable Purchased Entity and/or applicable Subsidiary} (all of the foregoing being the "**Released Subject Matter**").

Notwithstanding the foregoing, this Release shall not extend to any right that the Releasor or **[his/her]** heirs, executors, estate trustees, personal representatives and/or administrators may hereafter have to benefits under any policy of directors and officers insurance or to be indemnified by ● *{insert name of the applicable Purchased Entity and/or applicable Subsidiary}* **[pursuant to its by-laws]** or pursuant to any indemnity agreement or pursuant to [the Ontario Business Corporations Act/the **[limited] partnership agreement of ●]** in connection with having served as a director or officer of ● *{insert name of the applicable Purchased Entity and/or applicable Subsidiary}*

It is further agreed that for the consideration aforesaid, the Releasor shall not make any claim or commence or maintain any action or proceeding against any person in relation to or in any way arising out of the Released Subject Matter, in which any claim could arise against the Releasees or any of them for contribution or indemnity or for other relief over.

The Releasor acknowledges having had an adequate opportunity to read and consider this release and to obtain such advice in regard to it as the Releasor considers advisable.

If any provision of this Release or any part of any provision of this Release is held under any circumstances to be invalid or unenforceable in any jurisdiction, then: (i) such provision or part thereof shall, with respect to such circumstances and in such jurisdiction, be deemed amended to conform to applicable laws so as to be valid and enforceable to the fullest possible extent, (ii) the invalidity or unenforceability of such provision or part thereof under such circumstances and in such jurisdiction shall not affect the validity or enforceability of such provision or part thereof under any other circumstances or in any other jurisdiction, and (iii) such invalidity or unenforceability of such provision or part thereof shall not affect the validity or enforceability of the remainder of such provision or the validity or enforceability of any other provision of this Release. Each provision of this Release is separable from every other provision of this Release, and each provision of this Release is separable from every other part of such provision.

This Release shall be governed by, enforced, construed and interpreted in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

<Signature page follows>

DATED the ____ day of _________________, 2016.

______________________________	______________________________
Witness Name: ● Address: ●	●

EXHIBIT C

FORMS OF EASEMENTS

EASEMENT IN GROSS

WHEREAS ■ (the "**Grantee**") has requested ■ (the "**Grantor**") to grant to the Grantee an easement in gross to continue to use and maintain an electricity Transmission Line on, over and under certain lands owned by the Grantor hereinafter described;

AND WHEREAS the Grantor has agreed to grant such easement in gross to the Grantee upon the terms and conditions hereinafter set forth;

NOW THIS EASEMENT IN GROSS WITNESSES that, in consideration of the sum of ■ Canadian Dollars ($■ CAN) paid by the Grantee, the mutual covenants and agreements herein contained and other good and valuable consideration, it is hereby agreed by the parties hereto as follows:

1. **Lands and Authorized Usage**

   The Grantor hereby grants to the Grantee, its servants and agents a non-exclusive easement in gross to enter upon the lands described in the Transfer/Deed attached hereto (hereinafter referred to as the "**Easement Area**"), solely for the purpose of erecting, using, maintaining, repairing, reconstructing, adding to and relocating thereon electricity transmission lines, substations, communication lines (including fibre optics and third party telecommunications) comprised of all necessary existing and future poles and supports, wire, protective and insulating equipment, switching stations and substations and related equipment, hardware and accessories (hereinafter referred to as the "**Transmission Line**").

2. **Term**

   The term of the within easement in gross is in perpetuity.

3. **Taxes**

   The Grantee covenants to pay when due and payable any and all forms of taxes, rates, dues and assessments, whatsoever, now charged or hereafter to be charged upon the Easement Area or the Transmission Line or upon the Grantor on account thereof, or otherwise charged upon either party hereto due to the existence of this easement.

4. **Governmental Requirement/Approvals/Permits**

   The Grantee agrees to observe and comply at is sole expense with all governmental requirements, including all legislation, regulations and conditions, statutory and otherwise, that may from time to time be in force and which would affect in any manner the Easement Area or any other lands of the Grantor, or the use thereof by the Grantee, or any activities that may be undertaken by the Grantee, its servants or agents in connection herewith, and the Grantee shall have no recourse against the Grantor under any circumstance whatsoever for the cost thereof of for any damage that may be sustained by the Grantee in the consequence of complying with, carrying out or performing any such governmental requirements. Without limiting the generality of the foregoing, the Grantee will obtain all necessary approvals and permits (such as work permits, fire permits, water crossing approvals, etc.) from the applicable government agencies or authorities prior to commencement of any activities or operations so governed by the said authorities. The Grantor agrees to cooperate with the Grantee to the extent necessary for obtaining the requisite approvals and permits and agrees to execute any required documents related thereto.

5. Access ***[NTD insert registration number of ROW Agreement]***

Access to the Easement Area shall be in accordance with the provisions of a right-of-way agreement made between the Grantor and the Grantee registered as Instrument Number ____ ________________.

6. Trees and Vegetation/Clearing

(a) The Grantee will not cut down, damage or destroy any standing trees or other vegetation on the Easement Area or on any other lands of the Grantor save and except such trees and vegetation which must be cleared and kept cleared for the purpose of erecting and maintaining the Transmission Line, and such exception shall extend to other immediately adjacent lands of the Grantor only when necessary to trim or cut down and remove such trees as may now or hereafter interfere with or endanger the Transmission Line, which determination shall be solely and reasonably the Grantee's.

(b) The Grantee will remove, chip or otherwise dispose of all unmerchantable logs, tops, branches and other tree or woody waste material ("tree slash") greater than four (4") inches in diameter. All remaining tree slash can be left on the Easement Area provided in has been slashed down and trampled to within one foot of the surface of the ground. Mounding or windrowing of tree slash or other vegetative or organic debris generated by such clearing is not permitted on the Easement Area or on any other lands of the Grantor.

5. Repair

The Grantee shall reasonably and diligently repair, maintain and keep the Transmission Line safe and neat and in good and substantial repair at all times during the currency of this easement.

6. Waste Materials

The Grantee, its servants and agents will not deposit, dump, leave or abandon any waste material, debris, litter or rubbish on the Easement Area or on any other lands of the Grantor, and any such waste materials will be disposed of only in a manner and place approved by the Grantor and the governing authorities having jurisdiction thereover.

7. Aggregate Materials

The Grantee covenants and agrees with the Grantor that it will not use any gravel, sand or other aggregate materials found on the Easement Area or on any other lands of the Grantor without having first received written authorization from the Grantor.

8. Mining Activity

The Grantee agrees that in the event of any mining operations being conducted on or adjacent to or underneath the Easement Area, the person or firm conducting such mining operations shall be free to dig, tunnel or mine beneath the Easement Area provided always that such mining operations shall not fail to provide adequate support for the Transmission Line.

9. Other Uses/Users of the Easement Area

This easement does not in any manner limit the construction, use and maintenance of access roads, utilities or services by the Grantor or other parties authorized by it on, along or across the Easement Area, and at all times the Grantee agrees, at its sole expense, to maintain safe clearance of the Transmission Line over any such access roads now existing or hereafter to be constructed; and, without limiting the foregoing, the right is hereby reserved to the Grantor, its servants, agents and other persons or parties authorized by it, to use the Easement Area provided that any such use does not unduly interfere with the rights and obligations of the Grantee specified herein.

10. Relocation

Both parties hereto agree that upon issuance of written notification by the Grantor six (6) months in advance, the Grantor shall have the right, at its sole option, to relocate all or any section of the Transmission Line to adjacent lands owned or acquired by the Grantor at a location selected by the Grantor. Such relocation shall be carried out and completed at the expense of the Grantor and all necessary work and construction shall be in accordance with then current governmental regulations. The relocated Transmission Line shall be of at least equivalent structure, capacity and quality to that of the Transmission Line immediately prior to relocation.

11. Indemnification

The Grantee will at all times indemnify and save harmless the Grantor from any and all manner of claims, demands, losses, costs, charges, damages, expenses, actions or other proceedings, including those concerning any environmental liability and those for compensation under the *Worker's Compensation Act* or any similar Act, whatsoever, made or brought against, suffered by or imposed upon the Grantor or its property, servants, agents or any other person, firm or corporation in respect of any injury, death, loss or damage of or to any person or property (including, without limitation, servants, agents, permittees, invitees, licensees, lessees and property of the Grantor and the Grantee) directly arising out of, resulting from or sustained by reason of this easement, or the presence of the Transmission Line, or the Grantee's occupancy or use of the Easement Area or any buildings, fixtures, improvements, structures or chattels located thereon, or the Grantee's use of other lands of the Grantor for any purpose whatsoever, including ingress and egress from the Easement Area or any operation connected with this easement, or any breach of or non-performance by the Grantee of its covenants and obligations under this easement except if and to the extent that such claims are caused or contributed to by the negligence of the Grantor or any other users of the Easement Area or those who are responsible for in law. It is acknowledged and agreed by the Grantor and the Grantee that any liability of the Grantee hereunder does not encompass any indirect or consequential losses.

12. Liability Insurance

(a) The Grantee agrees to maintain at all times during the currency of this easement and during closure/removal/rehabilitation hereinbefore described, a minimum of Five Million ($5,000,000.00) Dollars comprehensive public liability insurance in respect of personal injury, death, loss or damage of or to any person or property of third parties, with insurers of recognized responsibility. The Grantor will be a named insured in the required liability insurance policy or policies and no such policy will be cancelled or allowed to lapse without at least thirty (30) days written notice having first been given to the Grantor. At all times during the currency hereof, the Grantee shall have a certificate of said liability insurance policy or policies for presentation to the Grantor forthwith upon written request therefor by the Grantor.

(b) The Grantor shall have the right, from time to time, to reasonably revise the amount or form or insurance coverage provided for herein as circumstances of changing economic conditions may warrant or require at any time during the term of this easement. The Grantor shall give the Grantee written notice of any such requested change at least thirty (30) days prior to the date of expiration of the then existing policy or policies, which notice constitutes an amendment to this easement and shall become a part hereof, and the Grantee agrees to and shall thereupon provide the Grantor with such revised policy or policies.

(c) Notwithstanding the foregoing, the Grantee covenants, alternatively, to self-insure under the same terms and conditions as above-contained. If the Grantee delivers notice in writing to this effect (the receipt of which is hereby acknowledged), the Grantee shall be deemed to be self-insured and shall not be in breach of this condition of easement.

13. Assignment

(a) The Grantee covenants that it will not assign or sublet this easement in gross without the consent in writing of the Grantor first had and obtained, such consent not to be unreasonably withheld or delayed. In the event the Grantor shall consent to the assignment of this easement in gross, the Grantee shall provide to the Grantor an original copy of the assignment.

(b) Notwithstanding the foregoing, the Grantee may, without consent but upon providing written notice of assignment to the Grantor, assign this easement in gross and all of its rights and obligations thereunder to an affiliate within the meaning of the *Ontario Business Corporations Act*.

16. Notices ***[NTD insert notice particulars]***

Any notice to be given under this easement in gross by either of the parties hereto shall be effectively given as follows:

TO: ■ (Grantee)

(insert contact person and fax or e-mail)

TO: ■ (Grantor)

(insert address and contact information)

The respective times of receipt of such notices shall be deemed to conclusively six (6) business days after the date the said notice is deposited in the mail or registered by courier, or if sent by fax or e-mail, twenty-four (24) hours after such notice is transmitted, excluding Saturdays, Sundays and statutory holidays in the country of destination,

17. <u>Governing Law</u>

The parties agree that the provisions of this agreement shall be governed by the laws of the Province of Ontario and Dominion of Canada.

18. <u>Enurement</u>

This agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF the parties hereto have executed this easement in gross under the hands of their respective signing officers duly authorized in that behalf.

■

Per: ________________________________
Name:
Title:

Per: ________________________________
Name:
Title:

I/We have authority to bind the corporation

■

Per: ________________________________
Name:
Title:

Per: ________________________________
Name:
Title:

I/We have authority to bind the corporation

SCHEDULE 1.1.7
AUDITED FINANCIAL STATEMENTS

Attached.

SCHEDULE 1.1.26
WORKING CAPITAL ADJUSTMENT

Working Capital shall be calculated in accordance with the following provisions:

1. Working Capital shall be prepared and calculated in accordance with IFRS, except as otherwise noted on this Schedule 1.1.26 and, to the extent consistent with IFRS and this Schedule 1.1.26, shall use the same accounting principles, practices, procedures, policies and methods (with consistent classifications, judgments, inclusions, exclusions, and valuation and estimation methodologies) used and applied by GLPT Holdings in the preparation of its Audited Financial Statements, except that such statements, calculations and determinations:

    (a) shall not include any purchase accounting or other adjustment arising out of the consummation of the transactions contemplated by this Agreement;

    (b) shall not be impacted by any actions taken by the Purchaser, either Purchased Entity or any Subsidiary after the Closing; and

    (c) shall calculate any reserve, accrual or other non-cash expense item on a *pro rata* (as opposed to monthly accrual) basis to account for a Closing Date that occurs on any date other than the last day of a calendar month.

2. "**Current Assets**" shall consist of the items and be calculated on a consolidated basis as set out in Appendix A to this Schedule 1.1.26.

3. "**Current Liabilities**" shall consist of the items and be calculated on a consolidated basis as set out in Appendix A to this Schedule 1.1.26.

APPENDIX A
WORKING CAPITAL

Attached.

Great Lakes Power Transmission
Net Working Capital

CURRENT ASSETS:	Dec 31, 2014 (audited)	Dec 31, 2015 (unaudited)	Closing Amount (unaudited)	Notes
Cash				
Great Lakes Power Transmission LP	5,201,444	3,340,099		
Great Lakes Power Transmission Holdings LP				
Total Cash	[redacted]	[redacted]	-	
Trade and other receivables				
Accrued revenue from IESO	3,331,073	3,053,437		
Miscellaneous billing	88,076	28,112		(1)
Employee loans	2,370	4,317		
Total Trade and other receivables	**3,421,520**	**3,085,866**	-	
Due from related parties				
Due from related parties	88,865	94,833	-	
Total Due from related parties	**88,865**	**94,833**	-	
Prepaid expenses & other				
Inventory	253,577	253,657		
Prepaid insurance	246,681	174,575		
Miscellaneous prepaids	167,980	205,206		(2)
Prepaid rent	27,821	28,016		
Total Prepaid expenses & other	**696,059**	**661,454**	-	
Total Current Assets	[redacted]	[redacted]	**$0**	
CURRENT LIABILITIES:				
Trade and other payables				
Connection deposits	1,075,938	593,130		
Trade payables and accruals	955,300	403,560		
Payroll liabilities	527,006	426,372		
Other payables	342,784	188,878		
Accrued interest	[redacted]	[redacted]		
Total Trade and other payables	[redacted]	[redacted]	-	
Due to related parties				
Due to related parties	217,968	197,679		
Total Due to related parties	**217,968**	**197,679**	-	
Total Current Liabilities	[redacted]	[redacted]	**$0**	
Net Working Capital	[redacted]	[redacted]	**$0**	

Notes:

(1) ***Miscellaneous billing*** - Receivables associated with services provided to third parties on a cost-recovery basis

(2) ***Miscellaneous prepaids*** - Includes various prepaid licenses, fees and annual memberships

[redacted]

SCHEDULE 1.1.85
PERMITTED LIENS

1. Any reference plans or plans registered pursuant to the *Boundaries Act* (Ontario).

2. All present and future motor vehicles, automotive equipment, materials-handling equipment and other goods leased from time to time by PHH Vehicle Management Services Inc. to GLPT.

3. No dealings indicator on PINs 31231-0018(LT), 31230-0011(LT) and 31232-0023(LT), (no transfer/charge without Minister consent).

4. Notices and restrictions registered as Instrument Nos. LT68363, LT68364, LT212306Z, LT212307Z (PIN 31176-0002(LT)).

5. An easement registered December 16, 1970 as Instrument No. LT70999 in favour of The Public Utilities Commission of the City of Sault Ste. Marie (PIN 31506-0125(LT)).

6. An easement registered September 23, 2009 as Instrument No. AL59837 in favour of Great Lakes Power Distribution Inc. (PIN 31346-0082(LT)).

7. An Order registered March 3, 1976 as Instrument No. T165612 (PIN 31563-0147)).

8. An easement registered November 19, 2007 as Instrument No. AL26720 in favour of Brookfield Power Wind Services Inc. and related charge in favour of BNY Trust Company of Canada registered as Instrument No. AL27108 (PIN 31350-0100(LT)).

9. A notice registered August 20, 2014 as [redacted]

10. All security granted in connection with the financing agreements listed as items 40 and 41 in Schedule 5.11.

SCHEDULE 1.1.116
UNAUDITED FINANCIAL STATEMENTS

Attached.

SCHEDULE 2.2
DEFERRAL ACCOUNTS

The following table represents known expenses that are included in an OEB-approved deferral account, for which GLPT will seek approval to collect in connection with a future rate application:

Type of Expense	Amount (in dollars)
Bulk Electric System costs	19,954.59
Comstock claim	99,214.24[1]
3 Year Collection costs	100,302.09[2]

[1] Note: $95,000.00 related to the Comstock claim was included in the GLPT Financial Model, dated November 2015.

[2] Note: This amount includes: (i) the interest carrying charges on OEB-approved deferral account expenses (based on the OEB prescribed rate); and (ii) rates under-collected by GLPT in prior periods, as at the date hereof.

SCHEDULE 3.2.1.2
RESIGNATIONS

1228185 Ontario Limited

Name	Position
Andrew McPhee	Vice President and General Manager
Jeff Rosenthal	Chief Operating Officer, Transmission and Director
Ian Kerr	Senior Vice President and Chief Operating Officer, Canadian Operations
Walter Di Cesare	Secretary, Vice President of Legal Services and General Counsel, Canadian Operations
Duane Fecteau	Chief Financial Officer
Scott Seabrook	Director of Administration
Basil Carruthers	Director

Great Lakes Power Transmission Holding Corp.

Name	Position
Jeff Rosenthal	President and Director
Joseph Cornacchia	Senior Vice President and Secretary
Duane Fecteau	Vice President and Director
Scott Seabrook	Director, Administration
Basil Carruthers	Director

GLPT GP

Name	Position
Jeff Rosenthal	President and Director
Joseph Cornacchia	Senior Vice President and Secretary
Duane Fecteau	Vice President and Director
Scott Seabrook	Director, Administration
Basil Carruthers	Director

[redacted]

SCHEDULE 5.2
CAPITAL OF THE PURCHASED ENTITIES AND THE SUBSIDIARIES

Entity	Authorized Capital	Issued and Outstanding Capital	Registered and Beneficial Owners
GLPT Holdings GP	Unlimited number of common shares	100 common shares	The Vendor: 100 common shares
GLPT Holdings II	Unlimited number of Class A Units and Class B Units	145,999,001 Units	The Vendor: 145,984,401 Class A Units GLPT Holdings GP: 14,600 Class B Units
GLPT Holdings	Unlimited number of Class A Units and Class B Units	145,999,001 Units	GLPT Holdings II: 145,984,401 Class A Units GLPT Holdings GP: 14,600 Class B Units
GLPT GP	Unlimited number of common shares	1 common share	The Vendor: 1 common share
GLPT	Unlimited number of Class A Units and Class B Units	20,285,009 Units	GLPT GP: 2 Class B Units GLPT Holdings: 20,285,007 Class A Units
1228185 Ontario Limited	Unlimited number of common shares	1 common share	GLPT: 1 common share
Great Lakes Power Transmission Holding Corp.	Unlimited number of common shares	1 common share	GLPT: 1 common share

SCHEDULE 5.6
NO CONTRAVENTION

[redacted]

SCHEDULE 5.10
NON-ARM'S LENGTH TRANSACTIONS

1. Transmission Connection Agreement between GLPT and Great Lakes Power Limited, dated February 24, 2012, as amended May 4, 2015.

2. Agreement respecting Fiber Optic Assets and Network between Great Lakes Power Limited and GLPT, by its general partner, GLPT GP, dated June 30, 2015.

3. All Leases and Identified Easements disclosed in Schedule 5.13 between Great Lakes Power Limited and GLPT.

4. Agreement respecting Radio Systems Assets between Great Lakes Power Limited and GLPT, by its general partner, GLPT GP, dated June 30, 2009.

5. Station Unaccompanied Access Agreement between GLPT, by its general partner, GLPT GP and Great Lakes Power Limited, dated June 25, 2015.

6. An unwritten Cost Sharing Agreement between GLPT and Great Lakes Power Limited for the total road maintenance costs (summer and winter maintenance) for the network of roads that run through the Montreal River area servicing both GLPT and Great Lakes Power Limited (generation) assets. Great Lakes Power Limited manages the maintenance contract and the relationship with the service provider and GLPT pays for 40% of the total maintenance costs based on actual invoicing received for said services.

7. Services Agreement between Brookfield Infrastructure Holdings (Canada) Inc. and GLPT, dated January 1, 2012.[3]

8. Transmission Connection Agreement between GLPT, by its general partner GLPT GP and Brookfield Power Wind Prince LP, dated September 28, 2006, as assigned by GLPL to GLPT, and as amended June 23, 2010.

9. Transmission Connection Agreement between GLPT, by its general partner, GLPT GP and Lake Superior Power Inc., dated January 31, 2003.

10. Agreement for Licensed Attachment between GLPT, by its general partner, GLPT GP and GLPL, dated July 22, 2010, as amended.

[3] Note: This Agreement shall be terminated on Closing.

SCHEDULE 5.11
MATERIAL CONTRACTS

FIRST NATIONS AND MINISTER OF NATURAL RESOURCES

1. Right of Way Permit (230 KV) between HER MAJESTY THE QUEEN in Right of Canada, GLPT, by its general partner, GLPT GP and Garden River First Nation, dated January 1, 2016.

2. Vegetation Management Services Agreement between GLPT, by its general partner GLPT GP and Garden River First Nation, dated August 1, 2011.

3. Vegetation Management Services Agreement between GLPT, by its general partner, GLPT GP and Batchawana Rankin First Nation, dated May 15, 2015.

4. Vegetation Management Services Agreement between GLPT, by its general partner GLPT GP and Michipicoten First Nation, dated September 1, 2011.

5. Memorandum of Agreement for Electrical Transmission Facilities (Appended to Land Use Permit) between HER MAJESTY THE QUEEN, in right of the Province of Ontario and Great Lakes Power Limited (and assigned to GLPT on December 11, 2007), dated January 1, 2001.

6. Host Agreement between Garden River First Nation and GLPT, by its general partner, GLPT GP, dated December 16, 2015.[4]

REGULATORY AGREEMENTS AND LICENSES

7. Electricity Transmission Licence of GLPT GP on behalf of GLPT, issued December 24, 2007.

8. Operating Agreement between Transmission Division of Great Lakes Power Limited and IESO (and assigned to GLPT on March 12, 2008), dated May 1, 2007.

9. Connection Facilities Agreement between Hydro One Networks Inc. and Great Lakes Power Limited Transmission Division (and assigned to GLPT on March 12, 2008) for the Operation of the 230 kV and 115kV Connections, dated July 1, 2002.

10. Transmission Connection Agreement between Great Lakes Power Limited and G-P Flakeboard Company (and assigned to GLPT on March 12, 2008), dated April 29, 2002.

11. Transmission Connection Agreement between GLPT and Essar Steel Algoma Inc., dated June 4, 2009.

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[4] This Agreement is dated "December 16, 2016" which is a typographic error (and is inconsistent with the date referred to in the header of each page of the Agreement). This error will be corrected in due course.

12. Transmission Connection Agreement between GLPT, by its general partner, GLPT GP and Algoma Power Inc., dated March 9, 2011.

13. Transmission Connection Agreement between GLPT, by its general partner, GLPT GP and Nodin Kitagan Limited Partnership and Nodin Kitagan 2 Limited Partnership, dated July 27, 2015.

14. Transmission Connection Agreement between GLPT, by its general partner, GLPT GP and Chi-Wiikwedong LP, dated March 25, 2015.

15. Transmission Connection Agreement between GLPT, by its general partner, GLPT GP and RTK WP Canada, ULC, dated August, 2014.

16. Transmission Connection Agreement between Great Lakes Power Limited and PUC Distribution Inc., dated April 26, 2002, as assigned to GLPT on March 12, 2008, as amended.

17. Transmission Connection Agreement between GLPT, by its general partner, GLPT GP and Wesdome Gold Mines Ltd., dated July 19, 2010.

THIRD PARTY SERVICE AGREEMENTS

18. Consulting Service Agreement between GLPT, by its general partner, GLPT GP and Power Engineers Inc., dated January 1, 2015, and amendment thereto.

19. Vegetation Management Services Agreement between GLPT, by its general partner, GLPT GP and 2385259 Ontario Limited o/a Wilderness Environmental Services, dated March 1, 2015.

20. Consulting Services Agreement between GLPT, by its general partner, GLPT GP and WSP Canada Inc., dated November 27, 2015.

21. Engineering Consulting Service Agreement between GLPT, by its general partner, GLPT GP and One Line Engineering Inc., dated May 1, 2015, and amendments thereto.

22. Master Consulting Agreement between GLPT, by its general partner, GLPT GP and AESI Acumen Engineered Solutions International Inc., dated May 13, 2015, and amendment thereto.

23. Blanket Consulting Agreement between GLPT, by its general partner, GLPT GP and Conestoga Rovers and Associates Limited, dated June 11, 2014, and amendments thereto.

24. Consulting Service Agreement between GLPT, by its general partner, GLPT GP and [redacted], dated January 1, 2015, and amendments thereto.

25. Maintenance & Technical Services Agreement between GLPT, by its general partner, GLPT GP and Alstom Grid Canada Inc., including Terms and Conditions thereto, dated March 15, 2013.

26. Maintenance & Construction Services Master Agreement between GLPT by its general partner, GLPT GP and Eptcon Ltd., dated November 27, 2015.

27. Consulting Services Agreement between GLPT, by its General Partner, GLPT GP and [redacted], effective January 1, 2010 and renewal agreement thereto, dated December 31, 2010.

28. Service Agreement between GLPT, by its General Partner, GLPT GP and Williams Electrical Training & Consulting Inc., effective January 1, 2011 and amendment agreement thereto, dated December 31, 2011.

29. Consulting Services Agreement between GLPT, by its General Partner GLPT GP and [redacted], effective March 17, 2014.

30. General Consulting Services Agreement between GLPT, by its General Partner, GLPT GP and Data Crush, dated May 1, 2015.

31. Consulting Services Agreement between GLPT, by its General Partner, GLPT GP and [redacted], effective October 27, 2014.

THIRD PARTY UTILITY AGREEMENTS

32. Station Unaccompanied Access Agreement between Algoma Power Inc. and GLPT, dated December 19, 2014.

33. Letter Agreement between Great Lakes Power Transmission Holding Corp. and Chi-Wiikwedong Holdings LP and Chi-Wiikwedong LP, dated September 25, 2014.

34. Agreement for Licensed Occupancy of Power Utility Transmission Poles between GLPT, by its general partner, GLPT GP and Algoma Power Inc., dated March 19, 2014.

35. Agreement for Licensed Attachment between GLPT, by its general partner, GLPT GP and PUC Telecom Inc., dated September 20, 2011.

36. Sublease and Licence of Occupation between GLPT (Sublandlord) and Great Lakes Power Distribution Inc. (Subtenant), dated July 1, 2009.

    (a) Amending Agreement #1 between GLPT, by its general partner, GLPT GP and Algoma Power Inc., dated March 10, 2011.

    (b) Extending and Amending Agreement between GLPT, by its general partner, GLPT GP, and Algoma Power Inc., dated December 22, 2014.

37. Agreement for Licensed Attachment between GLPT, by its general partner, GLPT GP, Great Lakes Power Transmission Holding Corp, Chi-Wiikwedong Holdings LP, by its general partner, Chi-Wiikwedong GP Inc. and Chi-Wiikwedong LP, by its general partner, Chi-Wiikwedong Holdings LP, by its general partner, Chi-Wiikwedong GP Inc., dated January 13, 2015.

RELATED PARTY AGREEMENTS

38. See the agreements referred to in Schedule 5.10.

REAL PROPERTY CONTRACTS

39. See the agreements referred to in Schedules 5.12 and 5.13.

FINANCING AGREEMENTS

40. Deed of Trust between GLPT (as assigned from Great Lakes Power Limited on March 12, 2008) and CIBC Mellon Trust Company, dated March 12, 2008, as supplemented by the First Supplemental Trust Indenture between GLPT (as assigned from Great Lakes Power Limited on March 12, 2008) and CIBC Mellon Trust Company, dated March 12, 2008 and all Bond Purchase Agreements and Security Agreements (as those terms are defined in the Deed of Trust) and all other guarantees, undertakings and agreements entered into in connection therewith or pursuant thereto.

41. GLPT Holdings Senior Secured Note Purchase Agreement, dated April 9, 2013, including the Notes, Limited Recourse Guarantees, Security Documents, Collateral Agency Agreement, Blocked Account Agreement and any and all other agreements, certificates, instruments or other documents from time to time entered into or delivered by or on behalf of any Credit Party related thereto (as those terms are defined in the Note Purchase Agreement).

EMPLOYMENT MATTERS

42. See the collective bargaining agreements referred to in Schedule 5.17.

PENSION, POST-RETIREMENT AND OTHER BENEFITS

43. See agreements referred to in Schedule 5.18.

IT AGREEMENTS

44. Software License and Services Agreement between H.T.E., Inc. and Great Lakes Power Limited, including Supplements.

45. Master License Agreement between GLPT and Environmental Systems Research Institute, Inc., dated October 27, 2009.

46. Customer Agreement between GLPT and O.N. Tel Inc., dated October 14, 2014.

47. IBM Agreement for Services including Maintenance between GLPT and IBM Canada Limited, dated August 10, 2010, including Statements of Work, dated August 15, 2013 and December 1, 2014.

48. Software License Agreement between GLPT, by its general partner, GLPT GP and Alstom Grid Inc., dated November 14, 2011.

49. Software Licensing Agreement between System Software Associates Inc. and Great Lakes Power, dated April 30, 1996, and amendments thereto.

50. Managed Firewall Services Agreement between GLPT and Gosecure Inc., dated April 29, 2015.

SCHEDULE 5.12
OWNED REAL PROPERTY

THIRD LINE SUBSTATION (TARENTORUS 19)

1. **PIN 31563-0143(LT)** - Lot 66, Registrar's Compiled Plan H739, Tarentorus except Parts 1, 2, 3 and 4 on Plan 1R8791, Sault Ste. Marie.

2. **PIN 31563-0147(LT)** – Part of Lot 67, Registrar's Compiled Plan H739, Tarentorus, designated as Parts 5-10 inclusive on Plan 1R12097, City of Sault Ste. Marie.

FOURTH LINE PROPERTY

3. **PIN 31564-0058(LT)** - Part of Lot 38, Registrar's Compiled Plan H741, Tarentorus as in T220780 (Schedule A 14thly), Sault Ste. Marie.

FIFTH LINE PROPERTY (TARENTORUS 18)

4. **PIN 31564-0101(LT)** - Lot 54, Registrar's Compiled Plan H741, Tarentorus, together with T220780, Sault Ste. Marie.

TARENTORUS - SECTION 21

5. **PIN 31506-0125(LT)** - Parcel 3329, Algoma West Section, being Part of Section 21, Tarentorus, as in LT29593 amended by LT32324, except LT30035 and Lots 1, 4 and 6, Expropriation Plan M-258, subject to LT40165 and LT70999, Sault Ste. Marie.

6. **PIN 31506-0126(LT)** - Parcel 3385, Algoma West Section, being Part of Section 21, Tarentorus, as in LT30035, except Lot 2, Expropriation Plan M-258, Sault Ste. Marie.

PENNEFATHER

7. **PIN 31350-0100(LT)** - Part of Section 24, Township of Pennefather as in T220780; District of Algoma.

GOULAIS BAY TRANSMISSION STATION

8. **PIN 31346-0082(LT)** - Lot 21, Registrar's Compiled Plan H-812, subject to RB640 and T-15805; Sault Ste. Marie.

BATCHAWANA TRANSMISSION STATION

9. **PIN 31302-0339(LT)** - Part of Section 36 Tilley, designated as Part 1 on Plan 1R-3450, subject to BC97, District of Algoma

D.A. WATSON TRANSMISSION STATION HIGH FALLS SUBSTATION

10. **PIN 31176-0002(LT)** - Parcel 423, Algoma Central Railway Lands, Township of Naveau, designated as Parts 1, 2 and 3, Plan 1R-9587 except an area of land containing 11 acres more or less being a right-of-way for power transmission line of the Great Lakes Power Company; subject to LT68364, LT26454 and LT113588, Michipicoten.

GARTSHORE TRANSMISSION STATION

11. **PIN 31231-0019(LT)** - Surface rights only, all of location CL 13852, designated as Part 1, Plan 1R-11005, Township of Peever, District of Algoma as in Crown Patent AL18166.

ECHO RIVER TRANSMISSION STATION

12. **PIN 31473-0101(LT)** - Part of Lots 24 and 37, RCP H766, as in T266124 and Parts 1 and 2, Plan 1R-5849, Macdonald, Meredith, Aberdeen Additional.

SCHEDULE 5.13
LEASES AND IDENTIFIED EASEMENTS

Leases

1. Sublease of Water Power Lease No. 161 for Township of Rix lands, notice of which was registered against title to PIN 31232-0023(LT) as Instrument No. AL31999 (Andrews Transmission Station).

2. Sublease of Water Power Lease No. 169 for Townships of Home and Peever lands, notice of which was registered against title to PINs 31230-0011(LT) and PIN 31231-0018(LT) (part of Gartshore Transmission Station).

3. Lease of Right-of-Way dated September 1, 1937 between The Algoma Central and Hudson Bay Railway Company, as lessor, and Great Lakes Power Company Limited, as lessee for lease of lands owned by the railway in multiple townships.

   This Lease has been amended and supplemented as follows:

   (a) Lease of Right-of-Way dated May 1, 1956 between The Algoma Central and Hudson Bay Railway, as lessor, and Great Lakes Power Company Limited, as lessee (widens existing 150 foot wide line in 1937 lease by 50 feet to 200 feet in Townships of Tronsen, Tolmonen and Home).

   (b) Lease of Right-of-Way dated September 1, 1957 between The Algoma Central and Hudson Bay Railway Company, as lessor, and Great Lakes Power Corporation Limited, as lessee (adds a 100 foot right of way in Townships of Nebonaionquet and Maness to existing 1937 leased lands).

   (c) Lease of a Right-of-Way dated March 1, 1958 between The Algoma Central and Hudson Bay Railway Company, as lessor, and Great Lakes Power Corporation Limited, as lessee (adds 100 foot wide right of way in Townships of Larson and Greenwood to existing 1937 leased lands).

   (d) Lease of Right-of-Way dated May 1, 1987 between Algoma Central Railway, as lessor, and Great Lakes Power Limited, as lessee (widens existing 150 foot wide line to 200 feet – 25 feet on either side of existing line – in the Townships of Naveau and Nebonaionquet).

   (e) Power Transmission Line Amending Agreement – Township Lands dated September 1, 1994 between Algoma Central Corporation and Great Lakes Power Limited.

   (f) Power Transmission Line Amending Agreement – Railway Lands dated September 1, 1994 between Algoma Central Corporation and Great Lakes Power Limited.

(g) Power Transmission Line Amending Agreement – Retained Lands dated May 30, 1997 between Algoma Central Corporation and Great Lakes Power Limited.

(h) Power Transmission Line Amending Agreement – Transferred Lands dated as of November 12, 2002 between 3011650 Nova Scotia Limited, 2016596 Ontario Inc. and Great Lakes Power Limited (2016596 Ontario Inc. owner of 1937 leased lands located in the Townships of Greenwood and Bullock).

(i) Power Transmission Line Amending Agreement – Transferred Lands dated October 27, 2004 between 3011650 Nova Scotia Limited, Interior Fibre Management Inc. and Great Lakes Power Limited (lands in 1937 lease north of Montreal River in Townships of Home and Larson were transferred to 3011650 Nova Scotia Limited which then transferred such lands to Interior Fibre Management Inc.).

4. Lease dated July 1, 2009 between Great Lakes Power Transmission LP as tenant and Great Lakes Power Limited as landlord, leasing all of the building at the property municipally known as 2 Sackville Road, Sault Ste Marie and legally described on PIN 31558-001(LT). Email notice dated July 12, 2013 from Great Lakes Power Transmission LP to Great Lakes Power Limited, giving notice of extension of the term of the lease to December 31, 2019.

5. Sublease dated July 1, 2009 between Great Lakes Power Transmission LP as sublandlord and Great Lakes Power Distribution Inc., now Algoma Power Inc., as subtenant, for the subletting of 42,778 square feet of office space and 11, 220 square feet of industrial space at 2 Sackville Road, Sault Ste Marie. Terms of the sublease were amended by an amending agreement dated March 10, 2011 and further amended and extended by an extending and amending agreement dated December 22, 2014.

Identified Easements

Attached.

Issues with respect to Leases and Identified Easements

Attached.

Schedule 5.13
Easements and Other Rights to use Real Property

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		115 KV LINE	
		MCMURRAY/LENDRUM	
1.	**31169-2205(LT)** **31169-2206(LT)** **31170-0051(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application to rectify and amend 22697 over Parcel 2236, AWS (b) Caution LT22697 registered April 1, 1939 is an easement from Algoma Ore Properties, Limited to Great Lakes Power Company Limited rectified to be an easement by Instrument LT114012 registered August 13, 1981 over part of mining claim SSM10530 being Part of Part 1, Plan 1R-11226, McMurray	**LT113588; LT22697; AL31987**
		NAVEAU	
2.	**31176-0001(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application rectifying caution LT26454 to be an easement; (b) Caution LT26454 is ACRL lease and easement dated September 1, 1937 affects Part of Parcel 12, ACRL	**LT26454; LT113588; AL31987**
3.	**31176-0001(LT)**	Instrument number LT218245 registered June 5, 1998 is an easement from Middle North Contracting Ltd. to Great Lakes Power Limited over Part of Parcel 12, ACRL	

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		NEBONAIONQUET	
4.	**31177-0001(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application rectifying caution LT26454 to be an easement; (b) Caution LT26454 is ACRL lease and easement dated September 1, 1937 affects Part of Parcel 37, ACRL	**LT113588; LT26454; AL31987**
5.	**31177-0015(LT)**	Instrument LT29914 registered June 5, 1952 is an easement from Olaf Palmgren to Great Lakes Power Corporation Limited over Part of Parcel 1700, AWS, Nebonaionquet	**LT113588; AL31987**
		RESTOULE	
6.	**31186-0001(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application rectifying caution LT26454 to be an easement; (b) Caution LT26454 is ACRL lease and easement dated September 1, 1937 affects Part of Parcel 9, ACRL	**LT113588; LT26454; AL31987**
		BULLOCK	
7.	**31209-0001(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application rectifying caution LT26454 to be an easement; (b) Caution LT26454 is ACRL lease and easement dated September 1, 1937 affects Part of Parcel 38, ACRL	**LT113588; LT26454; AL31987**
		GREENWOOD	
8.	**31218-0001(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application rectifying caution LT26454 to be an easement; (b) Caution LT26454 is ACRL lease and easement dated September 1, 1937 affects Part of Parcel 11, ACRL	**LT113588; LT26454; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		LARSON	
9.	**31223-0020(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application rectifying caution LT26454 to be an easement; (b) Caution LT26454 is ACRL lease and easement dated September 1, 1937 over Part of Index Plan ACR 25 and 26 being part of the Township of Larson as in LT26454	**LT26454; LT113588; AL31987**
		HOME	
10.	**31230-0001(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application rectifying caution LT26454 to be an easement; (b) Caution LT26454 is ACRL lease and easement dated September 1, 1937 affects Part of Parcel 24, ACRL	**LT26454; LT113588; AL31987**
		TOLMONEN	
11.	**31234-0001(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application rectifying caution LT26454 to be an easement; (b) Caution LT26454 is ACRL lease and easement dated September 1, 1937 affects Part of Parcel 30, ACRL	**LT113588; LT26454; AL31987**
		TRONSEN	
12.	**31235-0001(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application rectifying caution LT26454 to be an easement; (b) Caution LT26454 is ACRL lease and easement dated September 1, 1937 affects Part of Parcel 28, ACRL	**LT113588; LT26454; AL31987**
		ARCHIBALD:	
13.	**31301-0053(LT)**	Instrument CG12 registered October 1, 1931 is an easement from Wells-Higman Company to The Algoma District Power Company Limited over part of Lot 12, Concession 4, Archibald.	**T220780; T445270; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
14.	**31301-0053(LT)**	Instrument CG13 registered July 10, 1934 is an easement from Thomas J. McCauley and Sarah M. McCauley to The Algoma District Power Company Limited over Part of Lots 11 and 12, Concession 6 and Part of Lot 12, Concession 5, Archibald.	**T220780; T445270; AL31987**
15.	**31301-0053(LT)**	Instrument T10631 registered June 25, 1957 is an easement from Belco Timber Co. Limited to Great Lakes Power Corporation Limited over Part Lot 12, Concession 5, Archibald.	**T220780; T445270; AL31987**
16.	**31301-0053(LT)**	Instrument T10632 registered June 25, 1957 is an easement from Belco Timber Co. Limited to Great Lakes Power Corporation Limited over part of Lot 11, Concession 6, Archibald.	**T220780; T445270; AL31987**
17.	**31301-0053(LT)**	Instrument T10633 registered June 25, 1957 is an easement from Belco Timber Co. Limited to Great Lakes Power Corporation Limited over Part of Lot 12, Concession 6, Archibald.	**T220780; T445270; AL31987**
18.	**31301-0053(LT)**	Instrument T39697 registered July 13, 1961 is an easement from Roddis Lumber and Veneer Co. of Canada Limited to Great Lakes Power Corporation Limited over Part Lot 12, Concession 4, Archibald.	**T220780; T445270; AL31987**
		TILLEY:	
19.	**31302-0393(LT)**	Instrument BC78 registered October 1, 1931 is an easement from Wells-Higman, Company to The Algoma District Power Company Limited over Part of Sections 13 and 24, Tilley.	**T220780; T445270; AL31987**
20.	**31302-0208(LT)** **31302-0396(LT)**	Instrument BC79 registered October 1, 1931 is an easement from Christina S. Seymour to The Algoma District Power Company Limited over Part of the S½ of the SW¼ of Section 25, Tilley.	**T220780; T445269; T445270; AL31987**
21.	**31302-0209(LT)**	Instrument KB1170 registered July 10, 1934 is an easement from Thomas J. McCauley and Sarah M. McCauley to The Algoma District Power Company Limited over Part of Section 25 (known as the Begley Copper location), Tilley.	**T220780; T445269; T445270; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
22.	**31302-0208(LT)**	Instrument BC96 registered August 24, 1934 is an easement from William Jackson Torrance and Isabelle Mary Torrance to Great Lakes Power Company Limited over Part N ½ of the NW¼ of Section 25, Tilley.	**T220780; T445269; T445270; AL31987**
23.	**31302-0333(LT) 31302-0334(LT) 31302-0335(LT) 31302-0338(LT) 31302-0340(LT)**	Instrument BC97 registered October 1, 1934 is an easement from John B. Cochrane Executor of J.C.T. Cochrane to The Algoma District Power Company Limited over Part of Section 36, Tilley.	**T220780; T445269; T445270**
24.	**31302-0209(LT)**	Instrument T12284 registered September 23, 1957 is an easement from Ethel H. Holgate to Great Lakes Power Corporation Limited over Part of the Begley Copper Location within Section 25, Tilley.	**T445269; T445270; AL31987**
25.	**31302-0393(LT)**	Instrument T39698 registered July 13, 1961 is an easement from Roddis Lumber and Veneer Co. of Canada Limited to Great Lakes Power Corporation Limited over Part of Section 24, Tilley.	**T445269; T445270**
26.	**31302-0393(LT)**	Instrument T39699 registered July 13, 1961 is an easement from Roddis Lumber and Veneer Co. of Canada Limited to Great Lakes Power Corporation Limited over Part of Section 13, Tilley.	**T445269; T445270**
27.	**31302-0396(LT) 31302-0208(LT)**	Instrument T48442 registered August 10, 1962 is an easement from William Jackson Torrance and Isabelle Mary Torrance to Great Lakes Power Corporation Limited over Part N½ of the NW¼ of Section 25, and Part of the south Part of Section 25, Tilley.	**T445269; T445270**
28.	**31302-0340(LT) 31302-0338(LT) 31302-0333(LT) 31302 0334(LT) 31302-0335(LT)**	Instrument T91892 registered February 13, 1968 is an easement from Canada Permanent Trust Company, Executor of the Estate of J.C.T. Cochrane to Great Lakes Power Corporation Limited over Part of Section 36, Tilley.	**T445269; T445270; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		HAVILLAND:	
29.	**31306-0374(LT)**	Instrument XC226 registered November 30, 1951 is an easement from Humphrey S. Gray and Eleanor Goodenough Gray to Great Lakes Power Company, Limited over part of Broken Section 1, Havilland.	**T220780; T445270; AL31987**
30.	**31306-0370(LT)**	Instrument T12798 registered October 24, 1957 is an easement from Orvil Calvert and Ada M. Calvert to Great Lakes Power Corporation Limited over part of Lot 4, Plan H-413, Havilland.	**T445269; T445270; AL31987**
31.	**31306-0368(LT)**	Instrument T12840 registered October 28, 1957 is an easement from Stanley Kosek and Helena Kosek to Great Lakes Power Corporation Limited over Part of the N½ of Lot 2, Plan H-413, Havilland.	**T445269; T445270; T220780; AL29118; AL31987**
32.	**31306-0367(LT)**	Instrument T13187 registered November 19, 1957 is an easement from Arthur J. Valenti and Virginia Valenti to Great Lakes Power Corporation Limited over Part of Lot 1, Plan H-413, Havilland.	**T445269; T445270; T220780; AL29118; AL31987**
33.	**31306-0372(LT)**	Instrument T13371 registered December 3, 1957 is an easement from Eber Charles Roberts and Elizabeth Roberts to Great Lakes Power Corporation Limited over Part of Lot 6, Plan H-413, Havilland.	**T445269; T445270; T220780; AL29118; AL31987**
34.	**31306-0374(LT)**	Instrument T13647 registered December 24, 1957 is an easement from Virginia Hetler Globensky and Herbert E. McCauley to Great Lakes Power Corporation Limited over parts of Block D, Plan H-413, Havilland.	**T445269; T445270; T467856; AL31987**
35.	**31306-0374(LT)**	Instrument T13648 registered December 24, 1957 is an easement from Virginia Hetler Globensky and Herbert E. McCauley to Great Lakes Power Corporation Limited over Part of Section 1, Havilland.	**T445269; T445270; AL31987**
36.	**31306-0366(LT)**	Instrument T13649 registered December 24, 1957 is an easement from Virginia Hetler Globensky and Herbert E. McCauley to Great Lakes Power Corporation Limited over Part of Block A, Plan H-413, Havilland.	**T445269; T445270; T220780; AL29118; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
37.	**31306-0369(LT)** **31306-0370(LT)**	Instrument T13839 registered January 9, 1958 is an easement from Leslie W. Gump and Irma O. Gump to Great Lakes Power Corporation Limited over part of Lot 3, Plan H -413, Havilland.	**T445269; T445270; T220780; AL29118 AL31987**
38.	**31306-0371(LT)**	Instrument T17130 registered July 17, 1958 is an easement from Richard N. Heywood and Orpha Heywood to Great Lakes Power Corporation Limited over part of Lot 5, Plan H-413, Havilland.	**T445269; T445270; T220780; AL31987**
39.	**31306-0368(LT)**	Instrument T47082 registered June 19, 1962 is an easement from Thomas Stocco and Rina Stocco to Great Lakes Power Corporation Limited over part of the S½ of Lot 2, Plan H-413, Havilland.	**T445269; T445270; T220780; AL29118; AL31987**
		TUPPER:	
40.	**31307-0061(LT)**	Instrument TU12 registered October 1, 1931 is an easement from Samuel Bennett to The Algoma District Power Company Limited over Part S½ of the S½ of Lot 11, Concession 1, Tupper.	**T220780; T445269; T445270; AL29118; AL31987**
41.	**31307-0060(LT)**	Instrument TU13 registered July 10, 1934 is an easement from Wells-Higman Company to The Algoma District Power Company Limited over Part of Lots 11 and 12, Concession 3 and a part of Lot 12 in the 4th, 5th & 6th Concessions, Tupper.	**T220780; T445270; AL29118; AL31987**
42.	**31307-0061(LT)**	Instrument TU14 registered August 22, 1934 is an easement from Elmer E. Weed, Lizzie Weed, Joseph E. Devine, Alice E. Devine, Henry J. Vinkemulder, Belle B. Vinkemulder, Thomas J. McCauley and Sarah M. McCauley to Great Lakes Power Company Limited over part of the N½ of S½ and the N½ of Lot 11, Concession 1 and part of Lot 11, Concession 2, Tupper.	**T220780; T445269; T445270; AL29118; AL31987**
43.	**31307-0061(LT)**	Instrument T12292 registered September 23, 1957 is an easement from Frank M. Lasook and William Smith and Doreen E. Lasook and Annie Smith to Great Lakes Power Corporation Limited over Part of the S½ of the S½ of Lot 11, Concession 1, Tupper.	**T445269; T445270; AL29118; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
44.	**31307-0061(LT)**	Instrument T34321 registered November 7, 1960 is an easement from Algoma Forest Products Limited to Great Lakes Power Corporation Limited over part of the N½ of the NW¼ of Section 6, part of Lot 11, Concession 1, and part of Lot 11, Concession 2, Tupper.	**T445269; T445270; AL29118; AL31987**
45.	**31307-0060(LT)**	Instrument T39695 registered July 13, 1961 is an easement from Roddis Lumber and Veneer Co. of Canada Limited to Great Lakes Power Corporation Limited over part of Lot 12, Concession 3, Tupper.	**T445269; T445270; AL29118; T220780; AL31987**
46.	**31307-0060(LT)**	Instrument T39696 registered July 13, 1961 is an easement from Roddis Lumber and Veneer Co. of Canada Limited to Great Lakes Power Corporation Limited over part of Lot 11, Concession 3, Tupper.	**T445269; T445270; T220780; AL29118; AL31987**
47.	**31307-0060(LT)**	Instrument T39700 registered July 13, 1961 is an easement from Roddis Lumber and Veneer Co. of Canada Limited to Great Lakes Power Corporation Limited over part of Lot 12, Concession 6, Tupper.	**T445269; T445270; T220780; AL29118; AL31987**
48.	**31307-0060(LT)**	Instrument T39701 registered July 13, 1961 is an easement from Roddis Lumber and Veneer Co. of Canada Limited to Great Lakes Power Corporation Limited over Part of Lot 12, Concession 4, Tupper.	**T445269; T445270; T220780; AL29118; AL31987**
49.	**31307-0060(LT)**	Instrument T39702 registered July 13, 1961 is an easement from Roddis Lumber and Veneer Co. of Canada Limited to Great Lakes Power Corporation Limited over Part of Lot 12, Concession 5, Tupper.	**T445269; T445270; T220780; AL29118; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		VAN KOUGHNET:	
50.	[redacted]		
51.	[redacted]		
52.	[redacted]		
53.	[redacted]		
54.	[redacted]		
55.	[redacted]		
56.	[redacted]		

20699139.3

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
57.	[redacted]		
58.	[redacted]		
		FENWICK:	
59.	[redacted]		
60.	[redacted]		
61.	[redacted]		
62.	[redacted]		
63.	[redacted]		
64.	[redacted]		

20699139.3

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
65.	[redacted]		
66.	[redacted]		
67.	[redacted]		
68.	[redacted]		
69.	[redacted]		
70.	[redacted]		
71.	[redacted]		
72.	[redacted]		

20699139.3

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
73.	[redacted]		
74.	[redacted]		
75.	[redacted]		
76.	[redacted]		
77.	[redacted]		
78.	[redacted]		

20699139.3

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		PENNEFATHER:	
79.	[redacted]		
80.	[redacted]		
81.	[redacted]		
82.	[redacted]		
83.	[redacted]		
84.	[redacted]		
85.	[redacted]		
86.	[redacted]		

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
87.	[redacted]		
88.	[redacted]		
89.	[redacted]		
90.	[redacted]		
91.	[redacted]		
92.	[redacted]		

20699139.3

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		TARENTORUS, SECTION 6:	
93.	[redacted]		
94.	[redacted]		
95.	[redacted]		
96.	[redacted]		
97.	[redacted]		
98.	[redacted]		

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		TARENTORUS, SECTION 7:	
99.	**31508-0048(LT)**	(a) Instrument LT114012 registered August 13, 1981 is an application to rectify caution LT19717 to be an easement. (b) Instrument number LT19717 registered January 7, 1933 being a caution giving notice of an interest in land pursuant to memorandum of agreement/ grant of right of way from Robert J. Money and Christien Money to The Algoma District Power Company Limited over part of the N½ of the S½ of the NW¼ of Section 7, Part of Parcel 1869 AWS, Tarentorus.	**LT113588; LT114012**
100.	**31508-0057(LT) 31508-0058(LT) 31508-0059(LT)**	Instrument B2790 registered July 24, 1934 is an easement from William J. Money and Elizabeth Money to The Algoma District Power Company Limited over Part of N½ of the NW¼ of Section 7, Tarentorus.	**T220780; T445270; AL29118; AL31987**
101.	**31508-0077(LT) 31508-0161(LT)**	Instrument B2805 registered July 24, 1934 is an easement from Henry Selin, John Selin, Anna Selin and Mary Selin to The Algoma District Power Company Limited over part of the W½ of the NE¼ of the SW¼ of Section 7, Tarentorus.	**T220780; T445270; AL29118; AL31987**
102.	**31508-0073(LT) 31508-0074(LT) 31508-0075(LT) 31508-0076(LT) 31508-0161(LT)**	Instrument B2809 registered August 27,1934 is an easement from Jane Farquhar executrix and sole devisee of the estate of William Farquhar to The Algoma District Power Company Limited over Part S½ of the E½ of the SW¼ of Section 7, Tarentorus.	**T220780; T445270**
103.	**31508-0057(LT) 31508-0058(LT)**	Instrument T8995 registered March 21, 1957 is an easement from Melvin E. Daynard to Great Lakes Power Corporation Limited over Part of N½ of the N½ of the NW¼ of Section 7, Tarentorus.	**T220780; T445270; AL29118; AL31987**
104.	**31508-0077(LT)**	Instrument T9068 registered March 27, 1957 is an easement from Leonard Gamble to Great Lakes Power Corporation Limited over Part of the W½ of the NE¼ of the SW¼ of Section 7, Tarentorus.	**T220780; T445270; AL29118; AL31987**
105.	**31508-0073(LT) 31508-0074(LT) 31508-0075(LT) 31508-0076(LT)**	Instrument T20202 registered December 19, 1958 is an easement from Louis Lefebvre and Ida Lefebvre to Great Lakes Power Corporation Limited over Part of the S½ of the E½ of the SW¼ of Section 7, Tarentorus.	**T220780; T445270; AL29118; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
106.	**31508-0077(LT)** **31508-0161(LT)**	Instrument T20203 registered December 19, 1958 is an easement from Louis Lefebvre and Ida Lefebvre to Great Lakes Power Corporation Limited over Part of the W½ of the NE¼ of the SW¼ of Section 7, Tarentorus.	**T220780; T445270; AL29118; AL31987**
107.	**31508-0048(LT)**	Instrument LT45375 registered April 19, 1960 is an easement from Russell Ashmore to Great Lakes Power Corporation Limited over part of the N½ of the S½ of the NW¼ of Section 7, Part of Parcel 1869 AWS, Tarentorus.	**LT113588; LT114012 LT19717 AL29118 AL31987**
108.	**31508-0059(LT)**	Instrument T44017 registered January 22, 1962 is an easement from Mary Ernestine Hagen (formerly Mary Ernestine Hillier) to Great Lakes Power Corporation Limited over Part of the N½ of the N½ of the NW¼ of Section 7, Tarentorus.	**T220780; T445270; AL29118; AL31987**
109.	**31508-0058(LT)**	Instrument T45316 registered March 29,1962 is an easement from Mose J. Ouellette and Lena Ouellette to Great Lakes Power Corporation Limited over Part of the N½ of the N½ of the NW¼ of Section 7, Tarentorus.	**T220780; T445270**
110.	**31508-0052(LT)** **31508-0049(LT)** **31508-0051(LT)**	Instrument LT51638 registered July 18, 1962 is an easement from William Lamarche and Loretta Lamarche to Great Lakes Power Corporation Limited over Part of the S½ of the S½ of the NW¼ being Part of Parcel 1077 Algoma, Tarentorus.	**LT113588; AL31987**
		TARENTORUS, SECTION 18:	
111.	**31564-0027(LT)**	Instrument B2791 registered June 3, 1929 is an easement from August Saari and Marie Saari to The Algoma District Power Company Limited over part of the N½ of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; AL29118 AL31987**
112.	**31564-0033(LT)**	Instrument B2796 registered July 24, 1934 is an easement from John Kaunista and Selina Kaunista to The Algoma District Power Company Limited over part of the S½ of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; AL29118; AL31987**
113.	**31564-0059(LT)**	Instrument B2800 registered July 24, 1934 is an easement from William H. Palmer and Ellen Palmer to The Algoma District Power Company Limited over part of the SE¼ of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; AL29118; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
114.	**31564-0012(LT)**	Instrument B2803 registered July 24, 1934 is an easement from Yalmar Maki and Elina Maki to The Algoma District Power Company Limited over part of the E½ of the NW¼ of Section 18, Tarentorus.	**T220780; T445270; AL29118; AL31987**
115.	**31564-0028(LT)**	Instrument B2812 registered October 1, 1934 is an easement from Gilbert H. Johnston and Lila May Johnston to The Algoma District Power Company Limited over part of the S½ of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; T467856; AL29118; AL31987**
116.	**31564-0012(LT)**	Instrument T21846 registered April 16, 1959 is an easement from The Director, The Veterans' Land Act to Great Lakes Power Corporation Limited over part of the NW¼ of Section 18, Tarentorus.	**T220780; T445270; AL29118; AL31987**
117.	**31564-0033(LT)**	Instrument T21880 registered April 17, 1959 is an easement from The Director, The Veterans' Land Act to Great Lakes Power Corporation Limited over part of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; T467856; AL29118; AL31987**
118.	**31564-0028(LT)**	Instrument T21411 registered May 16, 1959 is an easement from Elizabeth Mathieu to Great Lakes Power Corporation Limited over Part of the S½ of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; T403360; AL29118; AL31987**
119.	**31564-0060(LT)**	Instrument T77424 registered February 25, 1966 is an easement from W.E. Muncaster to Great Lakes Power Corporation Limited over part of the SE¼ of Section 18, Tarentorus.	**No bulk Transfer**
120.	**31564-0027(LT)**	Instrument T92083 registered February 19, 1968 is an easement from the Montreal Trust Company executors and trustees of the estate of Harold Herbert Moeser to Great Lakes Power Corporation Limited over Part of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; AL29118; AL31987**
		TARENTORUS, SECTION 19:	

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
121.	**31563-0052(LT)**	Instrument B2799 registered July 24, 1934 is an easement from John H. Dumond to The Algoma District Power Company Limited over part of the E½ of the NW¼ of Section 19, Tarentorus.	**T220780; T445270; AL31987**
122.	**31563-0052(LT)**	Instrument T15756 registered May 16, 1958 is an easement from Andrew Stilin and Enola Ann Stilin to Great Lakes Power Corporation Limited over Part of the E½ of the NW¼ of Section 19, Tarentorus.	**T220780; T445270; AL31987**
		TARENTORUS, SECTION 30:	
123.	**31561-0118(LT)**	Instrument B2783 registered July 12, 1934 is an easement from George A. Dods and Edna Dods to The Algoma District Power Company Limited over part of the S½ of the N½ of the SE¼ of Section 30, Tarentorus, being part of Lot 22, RCP H-744.	**T220780; T445270; AL31984**
124.	**31561-0090(LT)**	Instrument B2788 registered July 24, 1934 is an easement from David W. Euler and Mary Euler to The Algoma District Power Company Limited over part of the N½ of the S½ and the S½ of the N½ of the NE¼ of Section 30, Tarentorus, being part of Lots 1 and 9, RCP H-744.	**T220780; T445270; AL31987**
125.	**31561-0037(LT) 31561-0041(LT) 31561-0035(LT) 31561-0157(LT) 31561-0158(LT)**	Instrument B2789 registered July 24, 1934 is an easement from Alfred E. Taylor and Elizabeth Taylor to The Algoma District Power Company Limited over part of the N½ of the NW¼ of the SE¼ of Section 30, Tarentorus, being part of Lots 20 and 21, RCP H-744.	**T220780; T445270; AL31987**
126.	**31561-0090(LT)**	Instrument B2792 registered July 24, 1934 is an easement from Wilfred E. Palmer and Lily M. Palmer to The Algoma District Power Company Limited over part of the N½ of the N½ of the NE¼ of Section 30, Tarentorus, being part of Lot 1, RCP H-744.	**T220780; T445270 AL31987**
127.	**31561-0122(LT)**	Instrument B2793 registered July 24, 1934 is an easement from Emma B. Reynolds to Great Lakes Power Company Limited over Part of the S½ of the S½ of the NE¼ Section 30, Tarentorus, being part of Lot 11, RCP H-744.	**T220780; T445270; AL31987**
128.	**31561-0009(LT) 31561-0008(LT) 31561-0004(LT) 31561-0006(LT) 31561-0003(LT)**	Instrument B2797 registered July 24, 1934 is an easement from Charles Wigmore and Alma Wigmore to The Algoma District Power Company Limited over Part N½ of the S½ of the SE¼ of Section 30, Tarentorus, being part of Lot 33, RCP H-744.	**T220780; T445270; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
	[redacted]		
129.	[redacted]		
130.	[redacted]		
131.	[redacted]		
132.	[redacted]		
133.	[redacted]		
134.	[redacted]		
135.	[redacted]		

20699139.3

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
136.	[redacted]		
137.	[redacted]		
138.	[redacted]		
		TARENTORUS, SECTION 31	
139.	[redacted]		
140.	[redacted]		
141.	[redacted]		
142.	[redacted]		

20699139.3

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		SAULT STE. MARIE	
143.	**31558-0001(LT)**	Instrument AL31995 registered March 13, 2008 is an easement from Great Lakes Power Limited to Great Lakes Power Transmission Holding Corp. over Parts 1 and 2 on Plan 1R-11504, Sault Ste. Marie.	
144.	**31577-0028(LT)** **31577-0030(LT)**	Instrument AL31996 registered March 13, 2008 is an easement from Great Lakes Power Limited to Great Lakes Power Transmission Holding Corp. over Parts 5-8 on Plan 1R-11506, Sault Ste. Marie.	
		KORAH, SECTION 1:	
145.	**31599-0063(LT)**	Instrument LT29721 registered March 1, 1952 is an easement from Joseph Alfred Jackson to Great Lakes Power Corporation Limited over part of the SE¼ of the NE¼ of Section 1, being Part of Parcel 3347 AWS, Korah.	**LT113588; AL31987**
146.	**31582-0005(LT)** **31582-0006(LT)** **31582-0007(LT)**	Instrument T7193 registered October 29, 1956 is an easement from Malcolm Harold Dickinson and Lenore Dickinson to Great Lakes Power Corporation Limited over part of Lot 19, Laura Wesley Subdivision 2, Plan 12898	**T220780; AL31987**
147.	**31582-0003(LT)** **31582-0214(LT)**	Instrument T7194 registered October 29, 1956 is an easement from Samuel B. Dickinson to Great Lakes Power Corporation Limited over part of Lot 19, Laura Wesley Subdivision 2, Korah, Plan 12898	**T220780; AL31987**
148.	**31582-0008(LT)**	Instrument T7828 registered December 6, 1956 is an easement from Attilio Berardinelli to Great Lakes Power Corporation Limited over part of Lot 19, Laura Wesley Subdivision 2, Korah, Plan 12898	**T220780; AL31987**
149.	**31568-0094(LT)**	Instrument T-8773 registered March 5, 1957 is an easement from William Yureychuk and Rose Yureychuk to Great Lakes Power Corporation Limited over part of Block 14, Stewart Survey, Korah	**T220780; AL31987**
150.	**31568-0094(LT)**	Instrument T-21136 registered February 25, 1959 is an easement from Fred Lawko and Mary Lawko to Great Lakes Power Corporation Limited over part of Block 14, Stewart Survey, Korah	**T220780**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
151.	**31584-0126(LT)** **31566-0258(LT)**	Instrument T39694 registered July 13, 1961 is an easement from Roddis Lumber and Veneer Co. of Canada Limited to Great Lakes Power Corporation Limited over Part of the S½ of the SW¼ of Section 24	**T220780; AL31987**
152.	**31599-0059(LT)**	Instrument LT50016 registered December 27, 1961 is an easement from Vilis Karklins and Elgin Karklins to Great Lakes Power Corporation Limited over part of the N½ of the N½ of the NE¼ of Section 1, Part Parcel 2976 AWS, Korah.	**LT113588; AL31987**
153.	**31599-0051(LT)**	Instrument LT50356 registered February 12, 1962 is an easement from Marion M. Pavelich and Bruna Rose Pavelich to Great Lakes Power Corporation Limited over part of the S½ of the N½ of the NE¼ of Section 1, Part Parcel 1280 AWS, Korah.	**LT113588; AL31987**
154.	**31570-0210(LT)** **31570-0212(LT)** **31570-0215(LT)**	Instrument T-113556 registered January 5, 1971 is an easement from Lyons Fuel Hardware and Supplies Limited to Great Lakes Power Corporation Limited over all of Lots 58, 98, 215 and 229, Plan 1703; Part of Lot 346, Plan 1703; Part of 30 foot laneway closed by by-law 293, Plan 1703; Part of Lennox Avenue closed by by-law 293, Plan 1703; Part of Shafer Avenue closed by by-law 293, Plan 1703; Part of 12 foot lane between Shafer Avenue and Peoples Road; Part of 12 foot lane between Shafer Avenue and Lennox Avenue	**T220780; AL31987**
155.	**31609-0104(LT)** **31609-0049(LT)** **31609-0048(LT)** **31609-0047(LT)** **31609-0046(LT)** **31609-0045(LT)** **31609-0044(LT)** **31609-0038(LT)** **31609-0034(LT)** **31609-0001(LT)** **31592-0280(LT)** **31592-0283(LT)** **31613-0308(LT)** **31613-0352(LT)** **31613-0353(LT)**	Instrument LT216273 (Land Titles) and T393141 (Registry) both registered January 20, 1998 is a transfer of easement from Algoma Steel Inc. to Great Lakes Power Limited over Parts 1 and 2, Plan 1R-9347; Parts 1-8 and 15, Plan 1R-9346; Parts 1-11, Plan 1R-9345; Parts 18-27, Plan 1R-9346; Parts 3, 4, 5, 6 and 8-13, Plan 1R-9347, Korah, Sault Ste. Marie, District of Algoma (see Schedule "B" PIN 31609-0176(R) for remaining Registry lands not converted to land titles qualified. **PATRICK STREET TO G.P. FLAKEBOARD**	**AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
156.	**31568-0025(LT)**	Instrument T403789 registered March 30, 1999 is an easement from Rosario Coccimiglio and Mario Coccimiglio to Great Lakes Power Limited over Part of Blocks 13 and 14, Stewart Survey of the Korah Block, Sault Ste. Marie, District of Algoma, described as Part 1, Plan 1R-9735.	**AL31987**
157.	**31592-0280(LT)**	Instrument AL9664 registered November 15, 2006 is an easement in gross granted by Algoma Steel Inc. to Great Lakes Power Limited over Part of Section 36, Korah; Part of Lots 19, 20, 21, 22 and 23 (now Part of Carleton Avenue, relocated by By-law 1444, as in Instrument 500); Part of a 14 foot lane and Part of St. Patrick Street, closed by By-law 1444, as in instrument 500, Block 4, Plan 402; designated as Parts 1 to 10 on Plan 1R-11240; Sault Ste. Marie	**AL31987**
		CLERGUE SUBSTATION TO PATRICK STREET SUBSTATION	
158.	**31576-0330(LT)**	Instrument AL61720 registered October 30, 2009 is an easement from The Corporation of the City of Sault Ste. Marie to Great Lakes Power Transmission Holding Corp. over Part of Hudson Street closed by By-law 2009-24, Plan Town Plot of St. Mary's; Sault Ste. Marie, being Part 2, Plan 1R-11717	
159.	**31576-0025(LT)** **31576-0024(LT)** **31578-0250(LT)**	Instrument T241680 registered December 19, 1983 is an easement from The Algoma Steel Corporation, Limited to Great Lakes Power Limited over part of Portage Street, Original Town Plot, now described as Part 1, Plan 1R-4611 and part of Portage Street, Original Town Plot, now described as Part 11, Plan 1R-4514	**AL31987**
160.	**31592-0280(LT)** **31579-0071(LT)**	Instrument T241681 registered December 19, 1983 is an easement from The Algoma Steel Corporation, Limited to Great Lakes Power Limited over Part of the Broken South West Quarter of Section 36, Korah, now designated as Parts 4, 5, 6, 7 and 8 on Plan 1R-4612; Sault Ste. Marie	**AL31987**
		KEHOE & COZENS	
161.	**31579-0071(LT)**	Instrument T241679 registered December 19, 1983 is an easement from Algoma Central Railway to Great Lakes Power Limited over Parts 1, 2 and 3, Plan 1R-4612, Kehoe and Cozens Subdivision.	**AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		ST. MARYS PAPER - BLOCK 31577	
162.	**31577-0066(LT)**	Instrument T454942 registered January 27, 2005 is an easement from St. Marys Paper Ltd. to Great Lakes Power Limited over Part of Hudson's Bay Company's lands, south side of Portage Street, Plan Town Plot of Sault Ste. Marie designated as Parts 1 and 3, Plan 1R-4290; Part of Parcel 1023, AWS	**AL31987**
163.	**31577-0035(LT)**	Instrument LT254163 registered January 27, 2005 is an easement from St. Marys Paper Ltd. to Great Lakes Power Limited on Part of Hudson's Bay Company's lands, south side of Portage Street, Plan Town Plot of Sault Ste. Marie designated as Part 1 and 3, Plan 1R-4290; Part of Parcel 1023, AWS	**AL31987**
164.	**31577-0025(LT)**	Instrument LT136132E registered July 31, 1985 is a transfer from Great Lakes Power Limited to The Corporation of the City of Sault Ste. Marie which reserves an easement over Part 4, Plan 1R-5809 in favour of Great Lakes Power Limited	**AL31987**
165.	**31577-0043(LT)**	Instrument LT136133E registered July 31, 1985 is a transfer from Great Lakes Power Limited to The Corporation of the City of Sault Ste. Marie which reserves an easement over Parts 1 & 4, Plan 1R-5709 in favour of Great Lakes Power Limited	**AL31987**
166.	**31577-0019(LT)**	Instrument T257669E registered July 31, 1985 is a transfer from Great Lakes Power Limited to The Corporation of the City of Sault Ste. Marie which reserves an easement over Parts 2 & 3, Plan 1R-5709 in favour of Great Lakes Power Limited	**AL31987**
167.	**31577-0019(LT)**	Instrument T257670E registered July 31, 1985 is a transfer from Great Lakes Power Limited to The Corporation of the City of Sault Ste. Marie which reserves an easement over Part 11, Plan 1R-5809 in favour of Great Lakes Power Limited	**AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		230kV TRANSMISSION LINES - THIRD LINE SUB TO MISSISSAGI T. S.	
		TARENTORUS, SECTION 19:	
168.	**31563-0082(LT)** **31563-0083(LT)**	Instrument T17131 registered July 15, 1958 is an easement from Valentine Euler (Valentine David Euler) to Great Lakes Power Corporation Limited over part of the SE¼ of the SE¼ of Section 19, Tarentorus.	**T220780; T445270; AL29118; AL31987**
169.	**31563-0078(LT)**	Instrument T169294 registered July 15, 1976 is an easement from Doran's Northern Ontario Breweries Limited to Great Lakes Power Corporation Limited over part of the S½ of the N½ of the SE¼ of Section 19, Part of Lot 60, RCP H739, designated as Part 1, Plan 1R-2569, Tarentorus.	**T220780; T445270; AL31987**
170.	**31563-0082(LT)**	Instrument T172116 registered September 30, 1976 is an easement from Bruce L. Walker and Margaret Walker to Great Lakes Power Corporation Limited over part of the SE¼ of the SE¼ of Section 19, Part of Lot 61, RCP H739, being Part 2, Plan 1R-2569, Tarentorus.	**T220780; T445270; AL31987**
171.	**31563-0078(LT)**	Instrument T211932 registered July 16, 1980 is an easement from Northern Breweries Ltd. to Great Lakes Power Corporation Limited over Part of Lot 60, RCP H-739 being Part 1 on Plan 1R-3800, Section 19, Tarentorus	**T445270; T301943; AL31987**
		TARENTORUS, SECTION 20:	
172.	**31510-0094(LT)**	Instrument T17855 registered August 26, 1958 is an easement from Lorne C. Palmer and Isabel Palmer to Great Lakes Power Corporation Limited over part of the SE¼ of the SW¼ of Section 20, being Part of Lot 45, RCP H737, Tarentorus.	**T220780; T445270; AL29118; AL31987**
173.	**31510-0200(LT)** **31510-0201(LT)** **31510-0219(LT)** **31510-0220(LT)**	Instrument T17856 registered August 26, 1958 is an easement from Lorne C. Palmer and Isabel Palmer to Great Lakes Power Corporation Limited over part of the SW¼ of the SW¼ of Section 20, being Part of Lot 38, RCP H737, Tarentorus.	**T220780; T445270; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
174.	**31510-0110(LT)**	Instrument T21412 registered March 16, 1959 is an easement from John Delbert Caul and Alice Marie Caul to Great Lakes Power Corporation Limited over part of SE¼ of the SE¼ of Section 20, being Part of Lot 55, RCP H737, Tarentorus.	**T220780; T445270; AL31987**
175.	**31510-0099(LT)**	Instrument T21598 registered March 31, 1959 is an easement from Lloyd Avery and Mildred Avery to Great Lakes Power Corporation Limited over part of the S½ of Section 20, being Part of Lot 47, RCP H737, Tarentorus	**T220780; T445270; AL29118; AL31987**
176.	**31510-0109(LT)**	Instrument T21599 registered March 31, 1959 is an easement from Lloyd Avery and Mildred Avery to Great Lakes Power Corporation Limited over part of the SW¼ of the SE¼ and part of the SE¼ of the SE¼, Section 20, being Part of Lot 56, RCP H737, Tarentorus Township.	**T220780; T445270; AL29118; AL31987**
177.	**31510-0102(LT) 31510-0103(LT)**	Instrument T21600 registered March 31, 1959 is an easement from C. Seaburn Weeks and Margaret Weeks to Great Lakes Power Corporation Limited over Part of Section 20, being Parts of Lots 48 and 50, RCP H737, Tarentorus	**T220780; T403337; T445270; AL29118; AL31987**
178.	**31510-0049(LT) 31510-0054(LT) 31510-0057(LT)**	Instrument T21667 registered April 2, 1959 is an easement from Edward Yadivisiak and Margaret Yadivisiak to Great Lakes Power Corporation Limited over part of the SE¼ of the SE¼ of Section 20, being Part of 1M-461, Tarentorus	**T220780; T445270; AL31987**
179.	**31510-0094(LT)**	Instrument T169293 registered July 15, 1976 is an easement from Isabel Palmer to Great Lakes Power Corporation Limited over part of the SE¼ of the SW¼, Section 20, being Part of Lot 45, RCP H737, designated as Part 1, Plan 1R-2568, Tarentorus	**T220780; T445270; AL29118; AL31987**
180.	**31510-0102(LT)**	Instrument T169295 registered July 15, 1976 is an easement from Defazio Enterprises Incorporated to Great Lakes Power Corporation Limited over part of the S½ of the SE¼ of Section 20, being Part 4 on Plan 1R-2568, being Part of Lot 48, RCP H737, Tarentorus.	**T22078; T445270; AL29118; AL31987**
181.	**31510-0051(LT) 31510-0052(LT) 31510-0057(LT)**	Instrument T169296 registered July 15, 1976 is an easement from Henry Ansel Wightman and Irma Sylvia Wightman to Great Lakes Power Corporation Limited over part of the E part of the N½ of the SE¼ of Section 20, being Part 9, Plan 1R-2568, being Part of Lot 57, RCP H737, Part of 1M-461	**T220780; T445270; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
182.	**31510-0099(LT)**	Instrument T169878 registered July 29, 1976 is an easement from Kenneth Norman Watkiss and Rosemary Watkiss to Great Lakes Power Corporation Limited over part of the S½ of the SW¼ of Section 20, being Part 3, Plan 1R-2568, being Part of Lot 47, RCP H737, Tarentorus	**T220780; T445270; AL29118; AL31987**
183.	**31510-0110(LT)**	Instrument T170070 registered August 4, 1976 is an easement from John Delbert Caul and Alice Marie Caul to Great Lakes Power Corporation Limited over part of the S½ of the SE¼ of Section 20, being Part 8, Plan 1R-2568, being Part of Lot 55, RCP H737, Tarentorus.	**T220780; T445270; AL31987**
184.	**31510-0103(LT)**	Instrument T170426 registered August 12, 1976 is an easement from Paul Defazio and Carolynn Defazio to Great Lakes Power Corporation Limited over part of the SE¼ of Section 20, now Part 5, Plan 1R-2568, being Part of Lot 50, RCP H737, Tarentorus.	**T220780; T445270; AL29118; AL31987**
185.	**31510-0050(LT) 31510-0053(LT) 31510-0057(LT)**	Instrument T170759 registered August 23, 1976 is an easement from Gertrud Eisbrenner to Great Lakes Power Corporation Limited over part of the S½ of the SE¼ of Section 20, being Part 7, Plan 1R-2568, being Part of Lot 54, RCP H737, Part of 1M-461,Tarentorus.	**T220780; T445270; AL31987**
186.	**31510-0217(LT) 31510-0218(LT)**	Instrument T283398 registered December 10, 1987 and Instrument T280873 registered September 24, 1987 correct Instrument T172565 registered October 14, 1976 being an easement from Raymond Belkosky and Kenneth Pierman to Great Lakes Power Corporation Limited over part of the N½ of the SW¼, Section 20, being Part of Lot 37, RCP H737, being Part 10, Plan 1R-2568, Tarentorus.	**T220780; T445270; T280873; T283398; AL31987**
187.	**31510-0219(LT) 31510-0220(LT)**	Instrument T294046 registered October 27, 1988 corrects Instrument T172736 registered October 19, 1976 being an easement from J.H. Ernest Ballentine to Great Lakes Power Corporation Limited over part of the S½ of the SW¼ and SE¼ of Section 20, part of Lot 38, RCP H737 being Part 1, Plan 1R-2568, Tarentorus.	**T220780; T445270; AL31987**
188.	**31510-0109(LT)**	Instrument T172737 registered October 19, 1976 is an easement from Lloyd Avery Contracting Limited to Great Lakes Power Corporation Limited over part of the S½ of the SE¼ of Section 20, being part of Lot 56, RCP H736 designated as Part 6, Plan 1R-2568, Tarentorus.	**T220780; T445270; AL29118; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		TARENTORUS, SECTION 21: (RCP H-736)	
189.	**31506-0149(LT)** **31506-0146(LT)** **31506-0134(LT)**	Instrument LT39805 registered July 30, 1958 is an easement from John P. Dunn and Blossom Dunn to Great Lakes Power Corporation Limited over part of the S½ of SE¼ of Section 21, Part of Parcel 3760, AWS, Tarentorus.	**LT113588;** **LT248702;** **AL31987**
190.	**31506-0050(LT)**	Instrument T17800 registered August 15, 1958 is an easement from Clair Robert Armstrong and Elsie A. Armstrong to Great Lakes Power Corporation Limited over part of the SW¼ of Section 21, Tarentorus.	**T220780;** **T445270;** **AL31987**
191.	**31506-0038(LT)** **31506-0039(LT)**	Instrument T17802 registered August 22, 1958 is an easement from Alec Wallenius and Beata Wallenius to Great Lakes Power Corporation Limited over part of the SW¼ of Section 21, Tarentorus	**T220780;** **T445270;** **AL31987**
192.	**31506-0045(LT)**	Instrument T17920 registered August 29, 1958 is an easement from Arvo Groondhal to Great Lakes Power Corporation Limited over part of the SW¼ of Section 21, Tarentorus.	**T220780;** **T445270;** **AL31987**
193.	**31506-0134(LT)**	Instrument LT64249 registered March 4, 1968 is an easement from John P. Dunn and Blossom Dunn to Great Lakes Power Corporation Limited over part of the SE¼ of Section 21, part of Parcel 3760, Section 21, Tarentorus.	**LT113588;** **AL31987**
194.	**31506-0039(LT)**	Instrument T169297 registered July 15, 1976 is an easement from Beata Wallenius to Great Lakes Power Corporation Limited over part of the SW¼ of Section 21, Part of Lot 27, RCP H736, being Part 4 on Plan 1R-2567, Tarentorus.	**T220780;** **T445270;** **AL31987**
195.	**31506-0038(LT)**	Instrument T170015 registered August 3, 1976 is an easement from Olive Marie Young to Great Lakes Power Corporation Limited over part of the SW¼ of Section 21, part of Lot 26, RCP H736, being Part 3, Plan 1R-2567, Tarentorus.	**T220780;** **T445270;** **AL31987**
196.	**31506-0050(LT)**	Instrument T170657 registered August 20, 1976 is an easement from Donald John Van Daele and Gloria Alice Van Daele to Great Lakes Power Corporation Limited over part of the W½ of the W½ of the SW¼ of Section 21, Part of Lot 37, RCP H736, being Part 1, Plan 1R-2567, Tarentorus.	**T220780;** **T445270;** **AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
197.	**31506-0149(LT)** **31506-0134(LT)**	Instrument LT87619 registered September 10, 1976 is an easement from John P. Dunn and Blossom Dunn to Great Lakes Power Corporation Limited over part of the S½ of SE¼ of Section 21, being Parts 3 and 5, Plan 1R-2856, Part of Parcel 3760, AWS, Tarentorus.	**LT113588; LT248702; AL31987**
198.	**31506-0045(LT)**	Instrument T280599 registered September 15, 1987 corrects a Planning Act problem in Instrument T173683 registered November 17, 1976 being an easement from Arvo Groondhal and Anne Groondhal to Great Lakes Power Corporation Limited over part of the SW¼ Section 21, part of Lot 33, RCP H736, being Part 2, Plan 1R-2567, Tarentorus.	**T220780; T445270**
199.	**31506-0121(LT)**	Instrument LT149735 registered April 30, 1987 corrects a Planning Act problem in Instrument 89942 registered February 28, 1977 being an easement from The Director, The Veterans' Land Act (Stanley Dominic Fisher) to Great Lakes Power Corporation Limited over part of the SE¼ of Section 21, being Part 4, Plan 1R-2586, Part of Parcel 2652 AWS, Tarentorus.	**LT113588; AL31987**
200.	**31506-0146(LT)**	Instrument LT101116 registered April 12, 1979 is an easement from Charles Dunn and Evelyn Dunn to Great Lakes Power Corporation Limited over part of Parcel 4842 AWS, being Part 2, Plan 1R-2586, Tarentorus.	**LT113588; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		TARENTORUS, SECTION 22: Part of Lot 18, RCP H-738	
201.	**31506-0171(LT)** **31506-0172(LT)**	Instrument T17445 registered August 6, 1958 is an easement from John Robert Pinder and Miriam Grace Pinder to Great Lakes Power Corporation Limited over part of the SW¼ of Broken Section 22, Tarentorus.	**T220780;** **T445270;** **AL31987**
202.	**31506-0171(LT)** **31506-0172(LT)**	Instrument T92086 registered February 27, 1968 is an easement from John Robert Pinder to Great Lakes Power Corporation Limited over part of the SW¼ of Broken Section 22, Tarentorus	**T220780;** **T445270;** **AL31987**
		FIRST RANGE (RANKIN) SOUTH OF OLD GARDEN RIVER ROAD, now part of Lots 8 & 9, Plan H-719:	
203.	**31506-0115(LT)** **31506-0117(LT)**	Instrument T21280 registered March 6, 1959 is an easement from Henry Ansel Wightman and Irma Sylvia Wightman to Great Lakes Power Corporation Limited over Part of Lot 1 in the First Range South of Old Garden River Road, Plan 139, Tarentorus, now part of Lots 8 & 9, RCP H-719	**T220780;** **T445270;** **T403340;** **AL31987**
204.	**31506-0117(LT)**	Instrument T170069 registered August 4, 1976 is an easement from Frederick Williamson Gordon and Sandra Ann Veronica Gordon to Great Lakes Power Corporation Limited over Part of Lot 1 in the First Range, Rankin Location, designated as Part 2, Plan 1R-2584, Tarentorus, now part of Lot 9, RCP H-719	**T220780;** **T445270;** **AL31987**
205.	**31506-0115(LT)**	Instrument T170265 registered August 10, 1976 is an easement from Heikki Kinnunen and Melba Kinnunen to Great Lakes Power Corporation Limited over Part of Lot 1, First Range, Rankin Location, being Part 3, Plan 1R-2584, Tarentorus. now part of Lot 8, RCP H-719	**T220780;** **T445270;** **AL31987**
206.	**31506-0115(LT)** **31506-0117(LT)**	Instrument T92085 registered February 27, 1968 is an easement from Henry Ansel Wightman and Irma Sylvia Wightman to Great Lakes Power Corporation Limited over Part of Lot 1, First Range, Rankin Location, Tarentorus, now part of Lots 8 & 9, RCP H-719	**T220780;** **T445270;** **AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		MACDONALD:	
207.	**31473-0097(LT)** **31473-0107(LT)**	Instrument T21278 registered March 6, 1959 is an easement from Robert H. Corboy and Kathleen I. Corboy to Great Lakes Power Corporation Limited over part of the S½ of the NE¼ of Section 3, MacDonald, Part Lot 10, RCP H766, Part of Lot 36 RCP H766	**T220780; T445270; T403359; AL31987**
208.	**31473-0097(LT)** **31473-0103(LT)**	Instrument T21319 registered March 11, 1959 is an easement from James T. Moss and Clara E. Moss to Great Lakes Power Corporation Limited over part of the S½ of the NW¼, Section 2, MacDonald, Part Lot 20, RCP H766, part of Lot 36 RCP H766	**T220780; T445270; T403341; AL31987**
209.	**31473-0077(LT)**	Instrument T21320 registered March 11, 1959 is an easement from William Cliffe to Great Lakes Power Corporation Limited over part of the S½ of the NE¼ of Section 3 and part of the S½ of the NW¼ of Section 3, MacDonald, Part Lot 9, RCP H766	**T220780; T445270; T403358; AL31987**
210.	**31473-0098(LT)**	Instrument T21352 registered March 12, 1959 is an easement from Robert John Cliffe to Great Lakes Power Corporation Limited over part of the S½ of the NE¼ of Section 2, MacDonald, Part Lot 21, RCP H766	**T220780; T445270; T403357; AL31987**
211.	**31473-0003(LT)**	Instrument LT44594 registered December 18, 1959 is an easement from Edgar L. Arsenault to Great Lakes Power Corporation Limited over part of the S½ of the NW¼ of Section 1, Part of Parcel 4234 AWS, MacDonald.	**LT113588; AL31987**
212.	**31473-0014(LT)** **31473-0016(LT)**	Instrument LT46495 registered September 12, 1960 is an easement from Tracey E. Carmichael, Administrator of the estate of Bernice B. Bushong to Great Lakes Power Corporation Limited over part of the S½ of the NE¼ of Section 1, Part of Parcel 947 AWS, Section 1, MacDonald, part of Parcel 4762, Sec AWS SRO	**LT113588; LT248072; AL31987**
213.	**31473-0097(LT)** **31473-0103(LT)**	Instrument T85854 registered April 28, 1967 is an easement from James T. Moss and Clara E. Moss to Great Lakes Power Corporation Limited over part of the S½ of the NW¼, Section 2, MacDonald, Part Lot 20, RCP H766, part of Lot 36 RCP H766	**T220780; T445270; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
214.	**31473-0003(LT)**	Instrument LT61793 registered May 2, 1967 is an easement from Rosa Dupuis to Great Lakes Power Corporation Limited over part of the S½ of the NE¼ of Section 1, Part of Parcel 4234 AWS, Section 1, MacDonald.	**LT113588; AL31987**
215.	**31473-0097(LT) 31473-0107(LT)**	Instrument T86024 registered May 5, 1967 is an easement from Francis Leon Lewis to Great Lakes Power Corporation Limited over part of the S½ of the NE¼ of Section 3, MacDonald, Part Lot 10, RCP H766, part of Lot 36 RCP H766	**T220780; T445270; AL31987**
216.	**31473-0098(LT)**	Instrument T90924 registered September 11, 1967 is an easement from Lorne Bain and Edna Bain to Great Lakes Power Corporation Limited over part of the S½ of the NE¼ of Section 2, MacDonald Part Lot 21, RCP H766	**T220780; T445270; AL31987**
217.	**31473-0014(LT)**	Instrument LT63937 registered January 12, 1968 is an easement from L.H. Shay Veneer of Canada Limited to Great Lakes Power Corporation Limited over part of the S½ of the NE¼ of Section 1, Parcel 4762 AWS, SRO, MacDonald	**LT113588; AL31987**
218.	**31473-0077(LT)**	Instrument T94415 registered June 25, 1968 is an easement from Morley Edward Trotter to Great Lakes Power Corporation Limited over part of the S½ of the broken NW¼ of Section 3, and part of the S½ of NE¼, Section 3, MacDonald, Part Lot 9, RCP H766	**T220780; T445270; AL31987**
219.	**31473-0103(LT)**	Instrument T270703 registered October 23, 1986 is an easement from Graham Nelder and Margaret Nelder to Great Lakes Power Limited over part of Lot 20, RCP H-766, being Part 1, Plan 1R-6605, Section 2, MacDonald	

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		MEREDITH:	
220.	**31474-0336(LT)** **31474-0337(LT)**	Instrument T17214 registered July 22, 1958 is an easement from Sawyer-Stoll Lumber Company of Canada Limited to Great Lakes Power Corporation Limited over Part of Section 4, Meredith.	**T220780; T445270; AL31987**
221.	**31474-0336(LT)** **31474-0337(LT)**	Instrument T17215 registered July 22, 1958 is an easement from Sawyer-Stoll Lumber Company of Canada Limited to Great Lakes Power Corporation Limited over a strip between the Township East Line and the East Line of Section 4, Eastern fraction or Gore, Meredith.	**T220780; T445270; AL31987**
222.	**31474-0074(LT)**	Instrument LT46495 registered September 12, 1960 is an easement from Tracey B. Carmichael administrator of the estate of Bernice B. Bushong to Great Lakes Power Corporation Limited over part of the S½ of the NE¼ of Section 1 and parts of Sections 5 and 6, Part of Parcel 948 AWS, Meredith, Part Parcel 4761 AWS, SRO	**LT113588; LT248702; AL31987**
223.	**31474-0336(LT)** **31474-0337(LT)**	Instrument T86023 registered May 5, 1967 is an easement from Sawyer-Stoll Lumber Company of Canada Limited to Great Lakes Power Corporation Limited over Part of Section 4 and Part of a strip laying immediately E of Section 4, Eastern fraction or Gore, Meredith.	**T220780; T445270; AL31987**
224.	**31474-0074(LT)**	Instrument LT63938 registered January 15, 1968 is an easement from L.H. Shay Veneer of Canada Limited to Great Lakes Power Corporation Limited over part of the S½ of the N½ of Section 5 and part of the S½ of the N½ of Section 6, part of Parcel 4761 AWS, Meredith.	**LT113588; AL31987**
		ABERDEEN:	
225.	**31386-0329(LT)**	Instrument LT42095 registered March 16, 1959 is an easement from Daniel Haines to Great Lakes Power Corporation Limited over part of the N½ of Lot 10, Concession 4, Part of Parcel 168 ACS, Aberdeen.	**LT113588; AL31987**
226.	**31386-0503(LT)**	Instrument LT42501 registered April 30, 1959 is an easement from Martin George Jones and Pearl A. Jones to Great Lakes Power Corporation Limited over part of the N½ of Lot 11, Concession 4, Part of Parcel 275 ACS, Aberdeen.	**LT113588**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
227.	**31386-0279(LT)**	Instrument LT42502 registered April 30, 1959 is an easement from David White and Lillian White to Great Lakes Power Corporation Limited over part of the N½ of Lot 12, Concession 4, Part of Parcel 1412 ACS, Aberdeen.	**LT113588; AL31987**
228.	**31386-0248(LT)**	Instrument LT42503 registered April 30, 1959 is an easement from Charles Gordon Wing and Beatrice Maud Wing to Great Lakes Power Corporation Limited over part of the S½ of the S½ of Lot 4, Concession 4, Part of Parcel 3032 ACS, SRO, Aberdeen.	**LT113588; AL31987**
229.	**31386-0345(LT)**	Instrument LT42619 registered May 13, 1959 is an easement from Lydia Rates to Great Lakes Power Corporation Limited over part of Lot 2, Concession 4, Part of Parcel 1286, Aberdeen	**LT113588; AL31987**
230.	**31386-0301(LT)**	Instrument LT42620 registered May 13, 1959 is an easement from Lydia Rates to Great Lakes Power Corporation Limited over part of the S part of Lot 2, Concession 4, Part of Parcel 833 ACS, Aberdeen	**LT113588; AL31987**
231.	**31386-0447(LT)**	Instrument T22926 registered June 3, 1959 is a Right of Way from Minnie May Cort to Great Lakes Power Corporation Limited over part of the S½ of Lot 1, Concession 4, ACS, Aberdeen, part of Parcel 1403, AWS	**T220780; T445270; AL31987**
232.	**31386-0503(LT)**	Instrument LT62044 registered June 16, 1967 is an easement from Martin George Jones and Pearl Aleene Jones to Great Lakes Power Corporation Limited over part of the N½ of Lot 11, Concession 4, Part of Parcel 275 ACS, Aberdeen.	**LT113588**
233.	**31386-0301(LT)** **31386-0345(LT)**	Instrument LT62114 registered June 28, 1967 is an easement from Lydia Rates to Great Lakes Power Corporation Limited over part of the S½ of Lot 2, Concession 4, Parcel 833 and Part of Parcel 1286, ACS, Aberdeen	**LT113588; AL31987**
234.	**31386-0329(LT)**	Instrument LT62149 registered July 6, 1967 is an easement from Ethel McClelland to Great Lakes Power Corporation Limited over part of the N½ of Lot 10, Concession 4, Part of Parcel 168 ACS, Aberdeen	**LT113588; AL31987**
235.	**31386-0279(LT)**	Instrument LT62304 registered August 3, 1967 is an easement from Harvey James White to Great Lakes Power Corporation Limited over part of the N½ of Lot 12, Concession 4, Part of Parcel 1412 ACS, Aberdeen	**LT113588; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
236.	**31386-0248(LT)**	Instrument LT64432 registered April 2, 1968 is an easement from Charles Gordon Wing to Great Lakes Power Corporation Limited over part of the S½ of the S½ of Lot 4, Concession 4, Part of Parcel 3032 ACS, SRO, Aberdeen	**LT113588; AL31987**
		GALBRAITH:	
237.	**31387-0014(LT)**	Instrument LT42846 registered June 3, 1959 is an easement from Minnie May Cort to Great Lakes Power Corporation Limited over part of the S½ of Lot 12, Concession 4, Part of Parcel 668 ACS, Galbraith	**LT113588; AL31987**
238.	**31387-0147(LT)**	Instrument LT42965 registered June 17, 1959 is an easement from Russell Hunter and Eileen Hunter to Great Lakes Power Corporation Limited over part of the N½ of Lot 4, Concession 3, Pt of Parcel 233 Algoma, Galbraith	**LT113588; AL31987**
239.	**31387-0243(LT) 31387-0244(LT)**	Instrument T23265 registered June 17, 1959 is an easement from Robert John Hunter and Ruby Hunter to Great Lakes Power Corporation Limited over part of the N½ of Lot 5, Concession 3, Galbraith.	**T220780; T445270; AL31987**
240.	**31387-0237(LT)**	Instrument T23406 registered June 23, 1959 is an easement from Charles Mitchell to Great Lakes Power Corporation Limited over part of Lot 3, Concession 3, Galbraith.	**T220780; T445270; AL31987**
241.	**31387-0106(LT) 31387-0046(LT)**	Instrument LT43021 registered June 24, 1959 is an easement from Cedric Stone and Edith M. Stone to Great Lakes Power Corporation Limited over part of the S½ of Lot 10, Concession 4, Part of Parcel 1108 ACS, Galbraith, now Parcel 4939, ACS, SRO.	**LT113588; LT248702; AL31987**
242.	**31387-0045(LT)**	Instrument LT43036 registered June 25, 1959 is an easement from Fred Daniel Martin to Great Lakes Power Corporation Limited over part of the N½ of Lot 8, Concession 3, Part of Parcel 1063 ACS, Galbraith.	**LT113588; AL31987**
243.	**31387-0038(LT)**	Instrument LT43845 registered September 28, 1959 is an easement from Frederick William Cort and Minnie May Cort to Great Lakes Power Corporation Limited over part of S½ of Lot 9, Concession 4, Part of Parcel 1005 Algoma Central Section, Galbraith.	**LT113588; AL31987**
244.	**31387-0146(LT)**	Instrument LT44665 registered December 29, 1959 is an easement from Murray Bean to Great Lakes Power Corporation Limited over part of the S½ of Lot 1, Concession 3, Part of Parcel 23 ACS, Galbraith	**LT113588; AL31987**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
245.	**31387-0243(LT)** **31387-0244(LT)**	Instrument T27849 registered December 30, 1959 is an easement from Donald W. Hagerty executor of the estate of Charles Henry Trower to Great Lakes Power Corporation Limited over part of the N½ of Lot 5, Concession 3, Galbraith	**T220780;** **T445270;** **AL31987**
246.	**31387-0047(LT)**	Instrument LT44883 registered February 5, 1960 is an easement from James MacLeod, Mildred Mary MacLeod and Charles Shultz to Great Lakes Power Corporation Limited over part of S½ of Lot 11, Concession 4, Part of Parcel 1160 Algoma Central Section, Galbraith	**LT113588;** **AL31987**
247.	**31387-0146(LT)**	Instrument LT62506 registered August 23, 1967 is an easement from Murray Bean to Great Lakes Power Corporation Limited over part of S½ of Lot 1, Concession 3, Part of Parcel 23 ACS, Galbraith	**LT113588;** **AL31987**
248.	**31387-0243(LT)** **31387-0244(LT)**	Instrument T89369 registered September 28, 1967 is an easement from Charles H. Kulpinski to Great Lakes Power Corporation Limited over part of the N½ of Lot 5, Concession 3, Galbraith.	**T220780;** **T445270;** **AL31987**
249.	**31387-0237(LT)**	Instrument T89549 registered October 4, 1967 is an easement from Heinrich Janssen to Great Lakes Power Corporation Limited over part of Lot 3, Concession 3, Galbraith.	**T220780;** **T445270;** **AL31987**
250.	**31387-0147(LT)**	Instrument LT63372 registered December 1, 1967 is an easement from Eileen Sarah Hunter to Great Lakes Power Corporation Limited over part of the N½ of Lot 4, Concession 3, Part of Parcel 233 Algoma, Galbraith	**LT113588;** **AL31987**
251.	**31387-0045(LT)**	Instrument LT63596 registered December 5,1967 is an easement from John Roderick McKenzie and Gertrude May McKenzie to Great Lakes Power Corporation Limited over part of the N½ of Lot 8, Concession 3, Part of Parcel 1063 ACS, Galbraith.	**LT113588;** **AL31987**
252.	**31387-0047(LT)**	Instrument LT63784 registered December 20, 1967 is an easement from Harvey James MacLeod and Mildred Mary MacLeod to Great Lakes Power Corporation Limited over part of the S½ of Lot 11, Concession 4, Part of Parcel 1160 Algoma Central Section, Galbraith	**LT113588**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
253.	**31387-0106(LT)**	Instrument LT64137 registered February 12, 1968 is an easement from Sydney Delaney and Marjorie Ann Delaney to Great Lakes Power Corporation Limited over part of the S½ of Lot 10, Concession 4, Part of Parcel 4939 Algoma Central Section, SRO, Galbraith	**LT113588; AL31987**
254.	**31387-0038(LT)**	Instrument LT64980 registered June 17, 1968 is an easement from Howard Erkine McEwen to Great Lakes Power Corporation Limited over part of the S½ of Lot 9, Concession 4, Part of Parcel 1005 ACS, Galbraith	**LT113588; AL31987**
		HAUGHTON:	
255.	**31388-0009(LT)**	Instrument LT45264 registered March 31, 1960 is an easement from Percy Edwin Hamilton to Great Lakes Power Corporation Limited over part of the S½ of Lot 5, Concession 2, Part of Parcel 922 ACS, Haughton	**LT113588; AL31987**
256.	**31388-0009(LT)**	Instrument LT66442 registered December 31, 1968 is an easement from Robert McCort Hamilton and Eva May Hamilton, Executors of the Estate of Percy Edwin Hamilton, to Great Lakes Power Corporation Limited over part of the S½ of Lot 5, Concession 2, Part of Parcel 922 ACS, Haughton	**LT113588; AL31987**
		GOULD:	
257.	**NOT PINNED**	Instrument LT43070 registered June 30, 1959 is an easement from John Stanley William Burrows to Great Lakes Power Corporation Limited over part of the S½ of Lot 10, Concession 1, Gould, Part of Parcel 2125, Section ACS	
258.	**31389-0013(LT)**	Instrument LT47847 registered March 29, 1961 is an easement from Margaret E. Foster to Great Lakes Power Corporation Limited over part of the N½ of Lot 11, Concession 1, Part of Parcel 1841 ACS, Gould.	**LT113588; AL31987**
259.	**NOT PINNED**	Instrument LT62169 registered July 10, 1967 is an easement from John Stanley William Burrows to Great Lakes Power Corporation Limited over part of the S½ of Lot 10, Concession 1, Gould, Part of Parcel 2125, Section ACS	

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
260.	**31389-0013(LT)**	Instrument LT63866 registered December 29, 1967 is an easement from Gene Montagnaro and Virginia Stewart McEachern Montagnaro to Great Lakes Power Corporation Limited over part of the N½ of Lot 11, Concession 1, Part of Parcel 1841, ACS, Gould	**LT113588; AL31987**
		WELLS:	
261.	**31410-0106(LT) 31410-0108(LT)**	Instrument LT43645 registered September 2, 1959 is an easement from Douglas Gulley to Great Lakes Power Corporation Limited over part of the N part of Lot 7, Concession 6, part of Parcel 5295 ACS, Wells	**LT113588; AL31987 (missing on 31410-0108)**
262.	**31410-0181(LT)**	Instrument LT60266 registered August 2, 1966 is an easement from Herbert Henry Garrod and Mary L. Garrod to Great Lakes Power Corporation Limited over part of the NE¼ of Lot 8, Concession 6, Part of Parcel 1598 Algoma, Wells	**LT113588; AL31987**
263.	**31410-0263(LT)**	Instrument LT60267 registered August 2, 1966 is an easement from Herbert Henry Garrod and Mary L. Garrod to Great Lakes Power Corporation Limited over part of the NW½ of the N½ of Lot 8, Concession 6, Part of Parcel 65 ACS, Wells	**LT113588; AL31987**
264.	**31410-0263(LT) 31410-0181(LT)**	Instrument LT63597 registered December 5, 1967 is an easement from Herbert Henry Garrod and Mary L. Garrod to Great Lakes Power Corporation Limited over part of the N½ of Lot 8, Concession 6, Part of Parcel 65 and Part of Parcel 1598 ACS, Wells	**LT11358; AL31987**
265.	**31410-0106(LT) 31410-0108(LT)**	Instrument LT64240 registered March 1, 1968 is an easement from Douglas Gulley to Great Lakes Power Corporation Limited over part of the E½ of Lot 7, Concession 6, Part of Parcel 5295 ACS, Wells	**LT113588; AL31987 (missing on 31410-0108)**
266.	**31410-0181(LT)**	Instrument LT69743 registered May 22, 1970 is an easement from Herbert Henry Garrod to Great Lakes Power Corporation Limited over Part of Parcel 1598 Algoma, being Part 1, AR972, Wells.	**LT113588; AL31987**
267.	**31410-0106(LT)**	Instrument LT70960 registered December 9, 1970 is an easement from Douglas Gulley and Verna E. Gulley to Great Lakes Power Corporation Limited over Part of Parcel 5295, ACS, being Part 1, AR972, Wells	**LT113588; AL31987**

GREAT LAKES POWER TRANSMISSION LP
Easements - Registry

Registered Easements, Leases, Rights-of-Way and Rights of Occupation

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		HAVILLAND	
268.	**31306-0373(R)**	Instrument T13647 registered December 24, 1957 is an easement from Virginia Hetler Globensky and Herbert E. McCauley to Great Lakes Power Corporation Limited over parts of Block D, Plan H-413, Havilland.	**T445269; T445270; T467856**
		VAN KOUGHNET	
269.	**31344-0164(R)**	Instrument LC278 registered July 10, 1934 is an easement from Peter A. Jones, Agness Jones and Francis McKie to The Algoma District Power Company Limited over part of the W½ of the SW¼ of Section 7, Van Koughnet.	**T220780; T445270**
270.	**31344-0188(R)**	Instrument LC282 registered November 7, 1934 is an easement from Isadore Rosenstein and Sarah Rosenstein to Great Lakes Power Company Limited over part of the S½ of the NW¼ and part of E½ of the SW¼ of Section 6, Van Koughnet.	**T445270; T467856**
271.	**31344-0188(R)**	Instrument LC412 registered May 18, 1949 is an easement from Lynch Timber Company to Great Lakes Power Corporation Limited over part of the E½ of the NW¼ of Section 7, Van Koughnet.	**T220780; T445270; T467856**
272.	**31344-0164(R)**	Instrument T8554 registered February 15, 1957 is an easement from Vaino Nikolai Gronroos Green and Margaret Ann Green to Great Lakes Power Corporation Limited over Part of the W½ of the SW¼ of Section 7, Van Koughnet.	**T445269; T445270**
273.	**31344-0188(R)**	Instrument T34321 registered November 7, 1960 is an easement from Algoma Forest Products Limited to Great Lakes Power Corporation Limited over part of the N½ of the NW¼ of Section 6, Van Koughnet.	**T445269; T445270; T467886;**
		FENWICK	
274.	**31346-0342(LT)**	Instrument T15842 registered May 22, 1958 is an easement from Amelia Nardi to Great Lakes Power Corporation Limited over Part of the NW¼ of Section 25, Fenwick.	**T220780; T445270; T467856; T467963 Note: converted to**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
			Land Titles on February 6, 2014
		PENNEFATHER	
275.	**31350-0233(R)**	Instrument AC162 registered October 1, 1931 is an easement from Elizabeth J. Dunseath to The Algoma District Power Company Limited over Part of the SE¼ of Section 25, Pennefather	**T220780; T445270; T467856; T467963**
276.	**31350-0232(R)**	Instrument AC163 registered March 1, 1932 is an easement from Alfred Benninghaus and Estella Benninghaus to Great Lakes Power Company Limited over Part of the S½ of the NE¼ and the N½ of the SE¼ of Section 24, Pennefather	**T220780; T445270; T467856; T467963**
277.	**31350-0230(R)**	Instrument No. AC175 registered July 10, 1934 is an easement from Thomas John McCauley and Sarah M. McCauley to Great Lakes Power Company Limited over Part of the NE¼of Section 1, Pennefather.	**T220780; T445269; T445270; T467856; T467963**
278.	**31350-0233(R)**	Instrument AC183 registered November 7, 1934 is an easement from Isadore Rosenstein and Sarah Rosenstein to Great Lakes Power Company Limited over part of the S½ of the NE¼ of Section 25, Pennefather.	**T445270; T220780; T467856; T467963**
279.	**31350-0235(R)**	Instrument AC185 registered November 24, 1934 is an easement from Fred W. McDowell and Ellen McDowell to The Algoma District Power Company Limited over part of the W½ of the NE¼ of Section 36, Pennefather.	**T220780; T445270; T467886; T467963**
		TARENTORUS, SECTION 7	
280.	**31508-0062(LT) 31508-0063(LT)**	Instrument B2790 registered July 24, 1934 is an easement from William J. Money and Elizabeth Money to The Algoma District Power Company Limited over Part of N½ of the NW¼ of Section 7, Tarentorus.	**T220780; T445270; T467856; T467963 Note: PIN converted from Registry to Land Titles on March 21, 2011**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
			and easement not brought forward.
281.	**31508-0062(LT)** **31508-0063(LT)**	Instrument T11483 registered August 12, 1957 is an easement from Hector C. Maitland and Thelma V. Maitland to Great Lakes Power Corporation Limited over part of the S½ of N½ of the NW¼ of Section 7, Tarentorus.	**T220780; T445270; T467856; T467963**
		TARENTORUS, SECTION 18	
282.	**31564-0132(LT)**	Instrument B2796 registered July 24, 1934 is an easement from John Kaunista and Selina Kaunista to The Algoma District Power Company Limited over part of the S½ of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; T467856; T467963 Note: PIN converted to Land Titles on March 21, 2011. Easement B2796 not brought forward.**
283.	**31564-0132(LT)**	Instrument B2812 registered October 1, 1934 is an easement from Gilbert H. Johnston and Lila May Johnston to The Algoma District Power Company Limited over part of the S½ of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; T467856; T467963 Note: PIN converted to Land Titles on March 21, 2011. Easement B2812 not brought forward.**
284.	**31564-0132(LT)**	Instrument T21880 registered April 17, 1959 is an easement from The Director, The Veterans' Land Act to Great Lakes Power Corporation Limited over part of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; T467856; T467963**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
			Note: PIN converted to Land Titles on March 21, 2011. Easement B21880 not brought forward.
285.	**31564-0132(LT)**	Instrument T43217 registered December 7, 1961 is an easement from Frank Lariviere and Wilhemina Lariviere to Great Lakes Power Corporation Limited over Part of the S½ of the SW¼ of Section 18, Tarentorus.	**T220780; T445270; T467856; T467963 Note: PIN converted to Land Titles on March 21, 2011. Easement B43217 not brought forward.**
286.	**31564-0132(LT)**	Instrument T83602 registered December 7, 1966 is a right-of-way from Clifford L. Corbett and Shirley A. Corbett to Great Lakes Power Corporation Limited over part of the S¼ of Section 18, Tarentorus	**T220780 T467856 T467963**
		TARENTORUS, SECTION 19	
287.	**31563-0038(R)**	Instrument B2801 registered July 24, 1934 is an easement from George H. Farmer, Wesley J. Farmer, Margaret I. Farmer and Mary J. Farmer to The Algoma District Power Company Limited over Part N½ of the SW¼ of Section 19, Tarentorus.	**T220780; T445270; T467856; T467963**
288.	**31563-0038(R)**	Instrument T10417 registered June 14, 1957 is an easement from Wesley J. Farmer and Margaret I. Farmer to Great Lakes Power Corporation Limited over part of the N½ of the SW¼ of Section 19, Tarentorus.	**T220780; T445270; T467856; T467963**

	PIN	EASEMENT NUMBERS AND PARTICULARS	Related Instruments
		KORAH	
289.	**31582-0010(R) 31582-0011(R)**	Instrument T7682 registered November 28, 1956 is an easement from Alistair Royce Dickinson and Theressa Mary Dickinson to Great Lakes Power Corporation Limited over Part of Lot 19, Laura Wesley Subdivision 2, Plan 12898, Korah	**T220780; T467887; T467888 (as to 31582-0010 only); T467898 (as to 31582-0011 only); T467963**
290.	**31582-0036(R)**	Instrument T7194 registered October 29, 1956 is an easement from Samuel B. Dickinson to Great Lakes Power Corporation Limited over part of Lot 19, Laura Wesley Subdivision 2, Korah, Plan 12898	**T220780; T467887; T467888; T467963**
291.	**31609-0176(R)**	Instrument T-393141 registered January 20, 1998 is an easement from Algoma Steel Inc. to Great Lakes Power Limited over Parts 9, 10, 11, 12, 13, 14, 16 and 17, Plan 1R-9346 and registered in the Algoma Land Titles division against certain absolute and qualified land titles lands as in instrument LT216273.	**T467963**
292.	**31609-0176(R)**	Instrument LT216273 registered January 20, 1998 is an easement from Algoma Steel Inc. to Great Lakes Power Limited over Parts 9, 10, 11, 12, 13, 14, 16 and 17, Plan 1R-9346.	**T467963**
		GALBRAITH	
293.	**31387-0239(R)**	Instrument T23264 registered June 17, 1959 is an easement from William C. Foster and Margaret Foster to Great Lakes Power Corporation Limited over part of the S½ of Lot 4, Concession 3 Galbraith.	**T220780; T445270; T467963**
294.	**31387-0239(R)**	Instrument T90667 registered November 27, 1967 is an easement from William C. Foster to Great Lakes Power Corporation Limited over part of the S½ of Lot 4, Concession 3, Galbraith.	**T220780; T445270; T467963**

Agreements, Licenses, Rights of Occupation

Each of the following agreements as renewed, amended, assigned, assumed, restated and/or replaced from time to time:

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]
5. [redacted]
6. [redacted]
7. [redacted]
8. [redacted]
9. [redacted]
10. [redacted]

11. [redacted]

12. [redacted]

13. [redacted]

20699139.3

Issues with respect to Leases and Identified Easements

1. [redacted]

2. [redacted]

3. [redacted]

4. [redacted]

5. [redacted]

6. [redacted]

[redacted]

7. [redacted]

8. [redacted]

9. [redacted]

10. [redacted]

11. [redacted]

12. [redacted]

13. [redacted]

14. [redacted]

SCHEDULE 5.14
ENVIRONMENTAL MATTERS

<u>Environmental Permits</u>:

1. Certificate of Approval from Ministry of Environment to Great Lakes Power Limited re: Andrews Transformer Station – T4, issued October 28, 2005.

2. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: Anjigami Transmission Station, issued April 10, 2012.

3. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: Batchawana Transmission Station, issued March 28, 2006.

4. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: Andrew Control Building, issued November 9, 2006.

5. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: Clergue Transmission Station, issued January 18, 2006.

6. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: Echo River Substation, issued January 20, 2009.

7. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: Goulais Transmission Station, issued September 28, 2007.

8. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: Hollingsworth Transformer Station, issued October 28, 2005.

9. Certificate of Approval from the Ministry of Environment to GLPT re: MacKay Transformer Station, issued May 11, 2011.

10. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: MacKay Transformer Station, issued January 20, 2006.

11. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: MacKay Substation, issued November 25, 2005.

12. Certificate of Approval from the Ministry of Environment to GLPT re: 2 Sackville Road, issued June 14, 2011.

13. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: Northern Avenue Transformer Station, issued October 28, 2005.

14. Certificate of Approval from the Ministry of Environment to Great Lakes Power Limited re: Third Line Transformer Station, issued December 5, 2005.

15. Certificate of Approval from the Ministry of Environment to GLPT GP, operating as GLPT re: Watson Transmission Station, issued April 10, 2012.

16. Amended Provisional Certificate of Approval for Great Lakes Power Limited, re: Province of Ontario, issued November 8, 2007.

17. List of Hazardous Waste Information Network Registered Sites, dated November 13, 2015.

18. Notice of Amendment to Pesticide Permit re: GLPT ROW from Batchewana T.S to outskirts of Sault Ste. Marie as per support document maps submitted.

SCHEDULE 5.15
ABORIGINAL MATTERS

Nil.

SCHEDULE 5.16
TAX MATTERS

Nil.

SCHEDULE 5.17
EMPLOYMENT MATTERS

Contracts of Employment Providing for Annual Payments of more than $300,000

Nil.

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

18. [redacted]

19. [redacted]

20. [redacted]

21. [redacted]

22. [redacted]

23. [redacted]

24. [redacted]

[redacted]

25. [redacted]

26. [redacted]

[redacted]

27. [redacted]

[redacted]

Nil.

[redacted]

Nil.

SCHEDULE 5.18
EMPLOYEE PLANS

1. Retirement Plan of GLPT (Defined Benefit Pension Plan), dated July 1, 2009 and amendments #1, 2, 3 and 4 thereto.

2. Amendment to Retirement Plan of GLPT, excluding inside union employees from eligibility and clarifying that gross earnings means the total remuneration received by the employee for a member represented by the Union, or the base salary for a member who is not represented by the Union, dated December 24, 2015.

3. Defined Contribution Pension Plan for Salaried Employees of GLPT, dated November 28, 2011 and amendment #1 thereto.

4. Amendment to Defined Contribution Pension Plan, defining inside union employee and setting the minimum contribution for those employees at 2.5%, dated December 24, 2015.

5. Group Benefit contract between GLPT with Great West Life Assurance Company policy #162565, dated November 20, 2013.

6. Long Term Disability contract between GLPT with RBC Life Insurance Company policy #48956-001, dated September 1, 2009.

7. GLPT Supplemental Pension Plan, as issued by board resolution annually (no separate plan text).

8. Retiree benefits as provided in the collective agreement, self-insured by GLPT.

9. Master Services Agreement between GLPT, by its general partner, GLPT GP and Ceridian Canada Ltd., dated August 26, 2015.

10. [redacted]

SCHEDULE 5.19[5]
INSURANCE

Policy	Name of Insurer	Policy Owner	Risks Insured Against	Amount of Coverage	Amount of any Deductible
Property	Starr Technical / Various	Brookfield Renewable Power Inc., including GLPT	All Risk Property	Replacement Cost	Per Day $250,000 / Business Interruption 60 Day Waiting Period
Terrorism	Lloyd's	Brookfield Renewable Power Inc, including GLPT	Terrorism	Replacement Cost	Per Day $100,000/ Business Interruption 7 Day Waiting Period
General Liability	ACE INA Insurance	Brookfield Renewable Power Inc., including GLPT	Third Party Property Damage, Bodily Injury	$2,000,000 each occurrence/ aggregate	NIL
Excess/ Umbrella Liability	Various	Brookfield Renewable Power Inc., including GLPT	Third Party Property Damage, Bodily Injury	$500,000,000 each occurrence/ aggregate	NIL
Automobile	Liberty Mutual Insurance	GLPT	Auto Liability, Physical Damage	$2,000,000 Third Party Liability	$500 Collision/ $500 Comprehensive
Directors & Officers Liability	AIG Insurance Company	Brookfield Asset Management, including GLPT	Directors & Officers	$50,000,000	$500,000
Non Owned Aircraft Liability	Global Aerospace	Brookfield Asset Management, including GLPT	Non-owned aircraft liability	$10,000,000	NIL
Crime Insurance	AIG Insurance Company	Brookfield Asset Management, including GLPT	Crime/ theft of money	$15,000,000	$50,000

[5] Effective as of the Closing Date, the Vendor shall remove the Purchased Entities and the Subsidiaries from the insurance policies set out on this Schedule 5.19. From and after the Closing Date, the Purchasers shall be responsible for establishing insurance policies to replace the insurance policies that will be terminated on the Closing Date, as described above.

SCHEDULE 5.21
REQUIRED PERMITS

[redacted] [redacted]

[redacted] [redacted]

SCHEDULE 5.24
ASSETS

1. GLPT GP holds one (1) common share of East-West Tie Inc.

SCHEDULE 9.2
CONDUCT OF BUSINESS UNTIL TIME OF CLOSING

1. Notwithstanding Section 9.2, on or prior to Closing, the Vendor shall be permitted, without the consent of the Purchaser, to take any actions, including incurring any expenditures or entering into any Contracts, in respect of any of the matters disclosed in the following documents made available to the Purchaser in the Data Room: (a) the GLPT Financial Model, dated November 2015; and (b) the GLPT 10 Year Capital Plan. For greater certainty, any such action described in the preceding sentence shall be deemed to be made by the Vendor in the ordinary course of Business.

2. Notwithstanding Section 9.2, the following Contracts may be executed by a Purchased Entity or a Subsidiary on or prior to Closing without the consent of the Purchaser:

   a. [redacted]

   b. [redacted]

   c. Agreement regarding the granting of easements, transfer of purchased lands and execution of a right of way agreement between GLPT [redacted].

   d. [redacted]

   e. [redacted]

   f. A Discrete Construction Agreement between GLPT, by its general partner, GLPT GP and [redacted] in respect of the construction of new transmission line.

   g. A Software License and Services Agreement between [redacted] and GLPT.

   h. [redacted]

   i. A Consulting Services Agreement between GLPT, by its General Partner, GLPT GP and [redacted].

j. A Service Agreement between GLPT, by its General Partner, GLPT GP and [redacted].

k. A Consulting Services Agreement between GLPT, by its General Partner GLPT GP and [redacted].

l. A General Consulting Services Agreement between GLPT, by its General Partner, GLPT GP and [redacted].

m. A Consulting Services Agreement between GLPT, by its General Partner, GLPT GP and [redacted].

SCHEDULE 9.6
VENDOR LETTERS OF CREDIT

[redacted] [redacted]

[redacted] [redacted]

CERTIFIED COPY OF RESOLUTION
OF THE BOARD OF DIRECTORS OF
HYDRO ONE INC.
(the "Corporation")

The undersigned hereby certifies that set out below is a true copy of a resolution passed by all of the Directors at the meeting of the Board of Directors of Hydro One Inc. held on January 14, 2016.

HYDRO ONE INC.
(the "Corporation")

RESOLUTIONS OF THE BOARD OF DIRECTORS

RESOLVED THAT:

Great Lakes Power Transmission Acquisition

1. The acquisition by the Corporation of GLPT at up to the maximum aggregate purchase price of **[intentionally deleted]** and otherwise on such terms as management may in its discretion determine, be and is hereby approved. The President and Chief Executive Officer or his delegate(s), is hereby authorized and directed, for and on behalf of the Corporation to negotiate, finalize, execute and deliver any and all documents, agreements, authorizations, elections or other instruments and to take any and all such further action as such officer or delegate(s), in such person's sole direction may deem necessary or desirable in order to give effect to the matters contemplated in this resolution, the execution and delivery of any such documents, agreements, authorizations, elections or other instruments or the doing of any such other act or thing by such person to be conclusive evidence of such determination.

Certified at Toronto, Ontario this 29th day of February, 2016.

Maureen Wareham
Corporate Secretary
Hydro One Inc.

BROOKFIELD INFRASTRUCTURE HOLDINGS (CANADA) INC.
(the "Corporation")

OFFICER'S CERTIFICATE

RE: Board of Directors Resolutions Authorizing the Sale of the Great Lakes Power Transmission Business

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I, James Rickert, do hereby certify that I am the Vice President and Secretary of the Corporation and that the resolutions attached hereto as Schedule A are true and correct extracts of the resolutions duly passed by the Board of Directors of the Corporation by written resolution dated the 28th day of January, 2016, which resolutions are in full force and effect and have not been modified or amended.

CERTIFIED TO BE TRUE this 1ST day of March, 2016.

by: ______________________
Name: James Rickert
Title: Vice President and Secretary

<u>SCHEDULE A</u>

<u>EXTRACT OF THE RESOLUTIONS OF THE BOARD OF DIRECTORS OF THE CORPORATION</u>

"WHEREAS, management of the Corporation has conducted a sale process in relation to the Great Lakes Power Transmission business owned by the Corporation ("**GLPT**");

NOW THEREFORE BE IT RESOLVED THAT:

2. The Corporation is hereby authorized to enter into a purchase agreement (the "**Purchase Agreement**") to be made between, among others, the Corporation and Hydro One Inc., in substantially the form provided to the directors, pursuant to which the Corporation will sell its interests in Great Lakes Power Transmission Inc., Great Lakes Power Transmission Holdings Inc. and Great Lakes Power Transmission Holdings II LP, on the terms and conditions contained in the Purchase Agreement, and with any amendments and variations, as the person(s) executing the Purchase Agreement may approve on the advice of external legal counsel, which approval shall be conclusively evidenced by the execution of the Purchase Agreement, which shall also provide conclusive evidence that the executed agreement is the Purchase Agreement authorized by this resolution.

3. Any one officer or director of the Corporation is hereby authorized to execute and deliver the Purchase Agreement in the name and on behalf of the Corporation and under its corporate seal or otherwise.

4. Any one officer or director of the Corporation is authorized and directed to execute and deliver in the name and on behalf of the Corporation and under its corporate seal or otherwise all such certificates, instruments, agreements and other documents and to do all such other acts and things, as in the opinion of such person may be necessary or desirable in connection with the foregoing resolutions.

5. The performance of all actions previously taken by any one officer or director of the Corporation in furtherance of the foregoing resolutions are hereby ratified, confirmed and approved in all respects.

6. These resolutions may be executed in counterparts (including by facsimile and e-mail transmissions), each of which so signed shall be deemed to be an original, and such counterparts together shall constitute one and the same instrument and shall be inserted in the minute book of the Corporation."


MANITOBA
ONTARIO
JAMES BAY
Thunder Bay
MINNESOTA
LAKE SUPERIOR
QUÉBEC
MICHIGAN
LAKE HURON
LAKE ONTARIO
NEW YORK
LAKE MICHIGAN
MICHIGAN
LAKE ERIE
hydroOne
Transmission Lines
High-Voltage Transmission Lines
115 kV
230 kV
500 kV
Transmission Interconnection
Existing

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 Service Life	Rate (%) 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 NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2013

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying financial statements of the Transmission Business (a business of Hydro One Networks Inc.), which comprise the balance sheet as at December 31, 2013, the statement 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 Transmission Business (a business of Hydro One Networks Inc.) as at December 31, 2013 and its statement of operations and comprehensive income, and 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 Transmission 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 Transmission 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 Transmission 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.
TRANSMISSION 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		
Transmission tariff *(Note 18)*	1,493	1,453
Other	36	29
	1,529	1,482
Costs		
Operation, maintenance and administration *(Note 18)*	388	414
Depreciation and amortization *(Note 4)*	326	320
	714	734
Income before financing charges and provision for payments in lieu of corporate income taxes	815	748
Financing charges *(Notes 5, 18)*	215	211
Income before provision for payments in lieu of corporate income taxes	600	537
Provision for payments in lieu of corporate income taxes *(Notes 6, 18)*	79	80
Net income	521	457
Other comprehensive income	–	–
Comprehensive income	521	457

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION 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)*	325	–
Accounts receivable (net of allowance for doubtful accounts – \$2; 2012 – \$2) (Notes 7, 18)	192	156
Materials and supplies	13	13
Regulatory assets *(Note 10)*	28	12
Deferred income tax assets *(Note 6)*	10	11
Derivative instruments *(Note 12)*	2	–
Other	8	7
	578	199
Property, plant and equipment *(Note 8)*		
Property, plant and equipment in service	14,140	13,522
Less: accumulated depreciation	4,951	4,698
	9,189	8,824
Construction in progress	737	712
Future use land, components and spares	91	91
	10,017	9,627
Other long-term assets:		
Regulatory assets *(Note 10)*	1,066	958
Intangible assets (net of accumulated amortization – \$104; 2012 – \$124) *(Note 9)*	116	107
Deferred debt costs	22	21
Derivative instruments *(Note 12)*	3	8
	1,207	1,094
Total assets	11,802	10,920

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS (continued)
At December 31, 2013 and 2012

December 31 (millions of Canadian dollars)	**2013**	**2012**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Notes 12, 13, 18)*	–	12
Accounts payable	60	66
Accrued liabilities *(Notes 6, 14, 15, 18)*	219	182
Accrued interest *(Note 18)*	61	58
Regulatory liabilities *(Note 10)*	55	2
Long-term debt payable within one year *(Notes 11, 12, 13, 18)*	327	370
	722	690
Long-term debt *(Notes 11, 12, 13, 18)*	4,954	4,632
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	636	604
Deferred income tax liabilities *(Note 6)*	806	698
Environmental liabilities *(Note 15)*	89	85
Regulatory liabilities *(Note 10)*	43	70
Net unamortized debt premiums	9	11
Asset retirement obligations *(Note 16)*	10	12
Long-term accounts payable and other liabilities	8	6
	1,601	1,486
Total liabilities	7,277	6,808
Contingencies and commitments (Notes 20, 21)		
Excess of assets over liabilities *(Notes 13, 17)*	4,525	4,112
Total liabilities and excess of assets over liabilities	11,802	10,920

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Carmine Marcello
Chair

Sandy Struthers
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION 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	521	457
Environmental expenditures	(6)	(6)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	301	298
Regulatory assets and liabilities	14	23
Deferred income taxes	(5)	(11)
Other	7	4
Changes in non-cash balances related to operations *(Note 19)*	48	12
Net cash from operating activities	880	777
Financing activities		
Long-term debt issued	652	611
Long-term debt retired	(370)	(276)
Payments to Hydro One Inc. to finance dividends	(108)	(163)
Other	(3)	(1)
Net cash from financing activities	171	171
Investing activities		
Capital expenditures *(Note 19)*		
Property, plant and equipment	(720)	(769)
Intangible assets	(4)	(17)
Other	10	7
Net cash used in investing activities	(714)	(779)
Net change in inter-company demand facility	337	169
Inter-company demand facility, beginning of year	(12)	(181)
Inter-company demand facility, end of year	325	(12)

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 transmission business (Transmission Business) operates a high-voltage electrical transmission network that represents almost all of the licensed transmission capacity in Ontario. The Transmission 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 Transmission 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 Transmission 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 Transmission 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 Transmission 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 Transmission 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 Transmission 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), 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 Transmission Business beginning with the year 2012.

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.

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 Transmission 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 Transmission Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Transmission 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 Transmission 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

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. 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. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Transmission 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 Transmission 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 Transmission Business has recognized regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Transmission 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 Transmission 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 transmission, 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.

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 Transmission 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
Transmission	57 years	1% – 2%	2%
Communication	21 years	1% – 5%	5%
Administration and service	14 years	6% – 10%	6%

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.

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 Transmission 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 Transmission 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 Transmission 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 Transmission 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 Transmission 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 transmission 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 Transmission 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 Transmission 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 Transmission 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 Transmission 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 Transmission Business' Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Depreciation of property, plant and equipment	274	269
Amortization of intangible assets	21	23
Asset removal costs	25	22
Amortization of regulatory assets	6	6
	326	320

5. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Interest on long-term debt	247	248
Other	6	8
Interest on inter-company demand facility	–	1
Less: Interest capitalized on construction and development in progress	(33)	(40)
Gain on interest-rate swap agreements	(4)	(6)
Interest earned on inter-company demand facility	(1)	–
	215	211

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	600	537
Canadian Federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	159	142
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(44)	(34)
Pension contributions in excess of pension expense	(13)	(11)
Interest capitalized for accounting but deducted for tax purposes	(9)	(10)
Overheads capitalized for accounting but deducted for tax purposes	(8)	(8)
Prior year's adjustments	(3)	–
Environmental expenditures	(2)	(2)
Post-retirement and post-employment benefit expense in excess of cash payments	1	–
Other	(3)	2
Net temporary differences	(81)	(63)
Net permanent differences	1	1
Total provision for PILs	79	80
Current provision for PILs	84	91
Deferred provision for PILs	(5)	(11)
Total provision for PILs	79	80
Effective income tax rate	13.17%	14.90%

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2013, $8 million receivable from the OEFC was included in accounts receivable on the Balance Sheet (December 31, 2012 – payable of $4 million included in accrued liabilities).

The total provision for PILs includes deferred recovery of PILs of $5 million (2012 – $11 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	(1,003)	(878)
Regulatory amounts not recognized for tax	(54)	(62)
Post-retirement and post-employment benefits expense in excess of cash payments	236	224
Environmental expenditures	24	26
Other	1	3
Total deferred income tax liabilities	(796)	(687)
Less: current portion	10	11
	(806)	(698)

During 2013, there was no change in the rate applicable to future taxes (2012 – a change in rate applicable to future rates generated a $47 million increase).

7. ACCOUNTS RECEIVABLE

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Accounts receivable – billed	19	15
Accounts receivable – unbilled	175	143
Accounts receivable, gross	194	158
Allowance for doubtful accounts	(2)	(2)
Accounts receivable, net	192	156

The write-offs and additions to the allowance for doubtful accounts for the years ended December 31, 2013 and 2012 were not material.

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2013 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	12,395	4,211	671	8,855
Communication	806	453	44	397
Administration and Service	421	213	22	230
Easements	609	74	–	535
	14,231	4,951	737	10,017

December 31, 2012 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	11,823	3,987	641	8,477
Communication	790	425	43	408
Administration and Service	394	198	28	224
Easements	606	88	–	518
	13,613	4,698	712	9,627

Financing charges capitalized on property, plant and equipment under construction were $33 million (2012 – $40 million).

9. INTANGIBLE ASSETS

December 31, 2013 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	214	101	2	115
Other	4	3	–	1
	218	104	2	116

December 31, 2012 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	218	122	9	105
Other	4	2	-	2
	222	124	9	107

Financing charges capitalized on intangible assets under development were immaterial in 2013 and 2012. The estimated annual amortization expense for intangible assets is as follows: 2014 – $20 million; 2015 – $20 million; 2016 – $20 million; 2017 – $20 million; and 2018 – $15 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. The Transmission Business has recorded the following regulatory assets and liabilities:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Regulatory assets:		
Deferred income tax regulatory assets	835	715
Post-retirement and post-employment benefits	133	139
Environmental	100	97
Pension cost variance	21	14
Long-term project development costs	5	5
Total regulatory assets	1,094	970
Less: current portion	28	12
	1,066	958
Regulatory liabilities:		
External revenue variance	81	61
Deferred income tax regulatory liability	7	2
PST savings deferral	3	3
Other	7	6
Total regulatory liabilities	98	72
Less: current portion	55	2
	43	70

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 Transmission 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 Transmission 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 $84 million (2012 – $93 million).

Post-Retirement and Post-Employment Benefits

The Transmission 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 $6 million (2012 – lower by $85 million).

Environmental

The Transmission 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 change in the environmental regulatory asset was insignificant (2012 – $2 million decrease) to reflect related changes in the PCB liability, and increased by $5 million (2012 – $1 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 Transmission Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2013 operation, maintenance and administration expenses would have been higher by $5 million (2012 – lower by $1 million). In addition, 2013 amortization expense would have been lower by $6 million (2012 – $6 million), and 2013 financing charges would have been higher by $4 million (2012 – $4 million).

Pension Cost Variance

A pension cost variance account was established for the Transmission 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 $7 million (2012 – $1 million).

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.

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 revenue. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

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 Transmission Business, PST was included in rates between July 1, 2010 and December 31, 2010 and recorded in a deferral account per direction from the OEB.

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 Transmission Business as at December 31, 2013 and 2012:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Long-term debt	5,276	4,994
Add: Unrealized marked-to-market loss[1]	5	8
Less: Long-term debt payable within one year	(327)	(370)
Long-term debt	4,954	4,632

[1] The unrealized marked-to-market loss relates to $150 million of Transmission Business' $325 million note due 2014, and $150 million of Transmission Business' $300 million note due 2015. The unrealized marked-to-market loss is offset by a $5 million (2012 – $8 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 Transmission Business'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				
$150 million of $325 million notes due 2014[1]	152	152	154	154
$150 million of $300 million notes due 2015[2]	153	153	154	154
Other notes and debentures[3]	4,976	5,397	4,694	5,574
	5,281	5,702	5,002	5,882

[1] The fair value of $150 million of Transmission Business' $325 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 $150 million of Transmission Business' $300 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 Transmission Business' $325 million and $300 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 Transmission Business' share of the Company's derivative instruments include $300 million of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt (2012 – $300 million). These interest-rate swaps are classified as fair value hedges. The Transmission Business' fair value hedge exposure was equal to about 6% (2012 – 6%) of its long-term debt. At December 31, 2013, the Transmission Business' interest-rate swaps designated as fair value hedges were as follows:

(a) a $150 million fixed-to-floating interest-rate swap agreement to convert $150 million of the $325 million notes maturing November 19, 2014 into three-month variable rate debt; and

(b) two $75 million fixed-to-floating interest-rate swap agreements to convert $150 million of the $300 million notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2013, the Transmission Business' share of interest-rate swaps classified as undesignated contracts consisted of the following:

(c) three $150 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 $30 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate on the $30 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 $30 million floating-to-fixed interest-rate swap agreement that locks in the floating-rate on the $30 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	325	325	325	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	5	5	–	5	–
	330	330	325	5	–
Liabilities:					
Long-term debt	5,281	5,702	–	5,702	–
	5,281	5,702	–	5,702	–

December 31, 2012 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Derivative instruments					
Fair value hedges – interest-rate swaps	8	8	–	8	–
	8	8	–	8	–
Liabilities:					
Inter-company demand facility	12	12	12	–	–
Long-term debt	5,002	5,882	–	5,882	–
	5,014	5,894	12	5,882	–

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 Transmission 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 Transmission Business' rate of return would reduce the Transmission Business' results of operations by approximately $19 million (2012 – $18 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 Transmission 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 Transmission 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	(3)	(5)
Unrealized loss (gain) on fair value interest-rate swaps	3	5
Net unrealized loss (gain)	–	–

At December 31, 2013, the amount of the Transmission Business' fair value hedges outstanding related to interest-rate swaps was $300 million (2012 – $300 million), with assets at fair value of $5 million (2012 – $8 million). During the years ended December 31, 2013 and 2012, there was no significant impact on the Transmission 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 Transmission 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 Transmission Business' allowance for doubtful accounts was $2 million (2012 – $2 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 and 2012, the Transmission Business' net accounts receivable aged more than 60 days were not significant.

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 Transmission 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 $279 million (2012 – $248 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 Transmission Business' long-term debt was $5,276 million (2012 – $4,994 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	325	249	3.2
2 years	330	239	2.9
3 years	300	223	4.4
4 years	405	217	5.2
5 years	412	195	2.8
	1,772	1,123	3.7
6 – 10 years	499	876	3.7
Over 10 years	3,005	2,594	5.5
	5,276	4,593	4.7

13. CAPITAL MANAGEMENT

The Transmission Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB.

The Transmission 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	327	370
Inter-company demand facility	(325)	12
	2	382
Long-term debt	4,954	4,632
Excess of assets over liabilities	4,525	4,112
Total capital	9,481	9,126

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	4,112	3,818
Net income	521	457
Payments to Hydro One to finance dividends	(108)	(163)
Excess of assets over liabilities, December 31	4,525	4,112

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 Transmission Business charged $20 million (2012 – $19 million) of post-retirement and post-employment benefit costs to operations, and capitalized $36 million (2012 – $24 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2013 were $19 million (2012 – $19 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $6 million (2012 – increased by $85 million).

The Transmission 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	20	21
Post-retirement and post-employment benefit liability	636	604
	656	625

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	81	16	97
Interest accretion	3	1	4
Expenditures	–	(6)	(6)
Revaluation adjustment	–	5	5
Environmental liabilities, December 31	84	16	100
Less: current portion	8	3	11
	76	13	89

Year ended December 31, 2012 (millions of Canadian dollars)	PCB	LAR	Total
Environmental liabilities, January 1	83	17	100
Interest accretion	4	–	4
Expenditures	(4)	(2)	(6)
Revaluation adjustment	(2)	1	(1)
Environmental liabilities, December 31	81	16	97
Less: current portion	10	2	12
	71	14	85

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	101	17	118
Less: discounting accumulated liabilities to present value	17	1	18
Discounted environmental liabilities	84	16	100

December 31, 2012 (millions of Canadian dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	99	17	116
Less: discounting accumulated liabilities to present value	(18)	(1)	(19)
Discounted environmental liabilities	81	16	97

At December 31, 2013, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2014	11
2015	11
2016	10
2017	2
2018	1
Thereafter	83
	118

At December 31, 2013, of the total estimated future environmental expenditures, \$101 million relates to PCBs (2012 – \$99 million) and \$17 million relates to LAR (2012 – \$17 million).

The Transmission 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 3.8% to 5.1%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission 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 Transmission 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 2024. Management judges that the Transmission 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 Transmission Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $101 million. These expenditures are expected to be incurred over the period from 2014 to 2024. The Company's annual review of environmental liabilities resulted in no PCB environmental liability revaluation adjustment for the Transmission Business in 2013 (2012 – revaluation adjustment to reduce PCB liability by $2 million).

LAR

The Transmission Business' best estimate of the total estimated future expenditures to complete its LAR program is $17 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 Transmission Business recorded a revaluation adjustment in 2013 to increase the LAR environmental liability by $5 million (2012 – $1 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 Transmission 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 $10 million (2012 – $12 million), related to its Transmission Business, consisting of $4 million (2012 – $4 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 $6 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.

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 Transmission Business makes payments to finance its share of the Company's common share and preferred share dividends. During 2013, the Transmission Business' payments to finance these dividends totaled $108 million (2012 – $163 million).

18. RELATED PARTY TRANSACTIONS

The Transmission 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 Transmission Business because they are controlled or significantly influenced by the Province. Transactions between these parties and the Transmission Business are described below.

The Transmission Business receives amounts for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Amounts received for the year ended December 31, 2013 were $1,509 million (2012 – $1,474 million). Consistent with the Company's revenue recognition policy, the Transmission Business recognized $1,493 million (2012 – $1,453 million) related to these services.

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 Transmission Business incurred $5 million (2012 – $5 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. In 2013, revenues of the Transmission Business related to the provision of construction and equipment maintenance services with respect to these service level agreements were $8 million (2012 – $8 million). Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were less than $1 million in both 2013 and 2012.

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 Transmission Business' allocation of this fee is $4 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	140	121
Accrued liabilities	6	(45)

Hydro One and Subsidiaries

The Transmission 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 Transmission 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 Transmission Business include $17 million (2012 – $16 million) related to the services received from Hydro One and its subsidiaries.

The Transmission 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 $247 million (2012 – $248 million), and interest income on the inter-company demand facility in the amount of $1 million (2012 – interest expense of $1 million). At December 31, 2013, the Transmission Business had accrued interest payable to Hydro One totaling $61 million (2012 – $58 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	(36)	4
Materials and supplies	–	3
Other assets	(1)	1
Accounts payable	4	(7)
Accrued liabilities	38	(18)
Accrued interest	3	6
Long-term accounts payable and other liabilities	2	–
Post-retirement and post-employment benefit liability	38	23
	48	12

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	(706)	(759)
Net change in accruals included in capital investments in property, plant and equipment	(14)	(10)
Capital expenditures – property, plant and equipment	(720)	(769)

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	(8)	(17)
Net change in accruals included in capital investments in intangible assets	4	–
Capital expenditures – intangible assets	(4)	(17)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Net interest paid	241	242
PILs	88	115

20. CONTINGENCIES

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Transmission 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 Transmission Business. However, the net assets of the Transmission 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 $30 million was allocated to the Company's Transmission 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 $75 million was allocated to the Company's Transmission Business.

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.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, 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 11, 2015.

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 (2013), 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, 2014. The effectiveness of these internal controls is reported to the Audit, Finance and Pension Investment Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been audited 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, Finance and Pension Investment Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit, Finance and Pension Investment 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, Finance and Pension Investment Committee, with and without the presence of management, to discuss their audit findings, if any.

The President and Chief Executive Officer and the Chief Financial Officer (Acting) 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	Ali R. Suleman
President and Chief Executive Officer	Chief Financial Officer (Acting)

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, 2014 and December 31, 2013, the consolidated statements of operations and comprehensive income, changes in 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 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, 2014 and December 31, 2013, 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 11, 2015

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars, except per share amounts)	**2014**	**2013**
Revenues		
Distribution (includes $159 related party revenues; 2013 – $160) *(Note 20)*	4,903	4,484
Transmission (includes $1,567 related party revenues; 2013 – $1,517) *(Note 20)*	1,588	1,529
Other	57	61
	6,548	6,074
Costs		
Purchased power (includes $2,633 related party costs; 2013 – $2,500) *(Note 20)*	3,419	3,020
Operation, maintenance and administration *(Note 20)*	1,192	1,106
Depreciation and amortization *(Note 5)*	722	676
	5,333	4,802
Income before financing charges and provision for payments in lieu of corporate income taxes	1,215	1,272
Financing charges *(Note 6)*	379	360
Income before provision for payments in lieu of corporate income taxes	836	912
Provision for payments in lieu of corporate income taxes *(Notes 7, 20)*	89	109
Net income	747	803
Net income (loss) attributable to noncontrolling interest *(Note 4)*	(2)	–
Net income attributable to the Shareholder of Hydro One Inc.	**749**	**803**
Other comprehensive income	–	–
Comprehensive income	**747**	**803**
Comprehensive income (loss) attributable to noncontrolling interest *(Note 4)*	(2)	–
Comprehensive income attributable to the Shareholder of Hydro One Inc.	**749**	**803**
Basic and fully diluted earnings per common share *(dollars) (Note 18)*	7,319	7,850
Dividends per common share declared *(dollars) (Note 19)*	2,696	2,000

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013

December 31 (millions of Canadian dollars)	**2014**	**2013**
Assets		
Current assets:		
Cash and cash equivalents *(Note 13)*	100	565
Accounts receivable (net of allowance for doubtful accounts – $66; 2013 – $36) *(Note 8)*	1,016	923
Due from related parties *(Note 20)*	224	197
Regulatory assets *(Note 11)*	31	47
Materials and supplies	23	23
Deferred income tax assets *(Note 7)*	19	18
Derivative instruments *(Note 13)*	2	6
Investment *(Notes 13, 20)*	–	251
Prepaid expenses and other assets	35	28
	1,450	2,058
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	25,356	23,820
Less: accumulated depreciation	9,134	8,615
	16,222	15,205
Construction in progress	1,025	1,078
Future use land, components and spares	154	148
	17,401	16,431
Other long-term assets:		
Regulatory assets *(Note 11)*	3,200	2,636
Intangible assets (net of accumulated amortization – $305; 2013 – $252) *(Note 10)*	276	313
Goodwill *(Note 4)*	173	133
Deferred debt issuance costs	36	36
Deferred income tax assets *(Note 7)*	7	11
Derivative instruments *(Note 13)*	–	6
Other	7	1
	3,699	3,136
Total assets	**22,550**	**21,625**

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)
At December 31, 2014 and 2013

December 31 (millions of Canadian dollars, except number of shares)	**2014**	**2013**
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	2	31
Accounts payable	173	135
Accrued liabilities *(Notes 15, 16)*	611	654
Due to related parties *(Note 20)*	227	230
Accrued interest	100	100
Regulatory liabilities *(Note 11)*	47	85
Derivative instruments *(Note 13)*	3	–
Long-term debt payable within one year (includes $252 measured at fair value; 2013 – $506) *(Notes 12, 13)*	552	756
	1,715	1,991
Long-term debt (includes $nil measured at fair value; 2013 – $256) *(Notes 12, 13)*	8,373	8,301
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	1,533	1,488
Deferred income tax liabilities *(Note 7)*	1,313	1,129
Pension benefit liability *(Note 15)*	1,236	845
Environmental liabilities *(Note 16)*	221	239
Regulatory liabilities *(Note 11)*	168	163
Net unamortized debt premiums	18	20
Asset retirement obligations *(Note 17)*	9	14
Long-term accounts payable and other liabilities	17	20
	4,515	3,918
Total liabilities	**14,603**	**14,210**
Contingencies and commitments (Notes 22, 23)		
Subsequent Event (Note 25)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 18, 19)*	323	323
Noncontrolling interest subject to redemption *(Note 4)*	21	–
Equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 18, 19)*	3,314	3,314
Retained earnings	4,249	3,787
Accumulated other comprehensive loss	(9)	(9)
Noncontrolling interest *(Note 4)*	49	–
Total equity	**7,603**	**7,092**
	22,550	**21,625**

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Sandra Pupatello
Chair

George L. Cooke
Chair, Audit, Finance and Pension Investment Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the years ended December 31, 2014 and 2013

Year ended December 31, 2014 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Noncontrolling Interest**	**Total Equity**
January 1, 2014	3,314	3,787	(9)	–	7,092
Net income	–	749	–	(1)	748
Other comprehensive income	–	–	–	–	–
Amount contributed by noncontrolling interest	–	–	–	50	50
Dividends on preferred shares	–	(18)	–	–	(18)
Dividends on common shares	–	(269)	–	–	(269)
December 31, 2014	3,314	4,249	(9)	(49)	7,603

Year ended December 31, 2013 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Noncontrolling Interest**	**Total 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

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Operating activities		
Net income	747	803
Environmental expenditures	(18)	(16)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	641	597
Regulatory assets and liabilities	(69)	3
Deferred income taxes	10	(2)
Other	–	8
Changes in non-cash balances related to operations *(Note 21)*	(55)	11
Net cash from operating activities	1,256	1,404
Financing activities		
Long-term debt issued	628	1,185
Long-term debt retired	(776)	(600)
Amount contributed by noncontrolling interest *(Note 4)*	72	–
Dividends paid	(287)	(218)
Change in bank indebtedness	(29)	(11)
Other	(3)	(5)
Net cash from (used in) financing activities	(395)	351
Investing activities		
Capital expenditures *(Note 21)*		
Property, plant and equipment	(1,481)	(1,308)
Intangible assets	(23)	(79)
Acquisition of Norfolk Power Inc. *(Note 4)*	(66)	–
Proceeds from investment	250	–
Other	(6)	2
Net cash used in investing activities	(1,326)	(1,385)
Net change in cash and cash equivalents	(465)	370
Cash and cash equivalents, beginning of year	565	195
Cash and cash equivalents, end of year	**100**	**565**

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., Hydro One Lake Erie Link Company Inc., Norfolk Power Inc. (Norfolk Power), and Hydro One B2M Holdings. 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.

Hydro One performed an evaluation of subsequent events through to February 11, 2015, 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 businesses of Hydro One Networks and B2M Limited Partnership (B2M LP). The Company's consolidated Distribution Business includes the separately regulated distribution businesses of Hydro One Networks and the newly acquired Norfolk Power, as well as the subsidiaries Hydro One Brampton Networks and Hydro One Remote Communities.

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. Up to the year ended December 31, 2014, Hydro One Brampton Networks used Canadian GAAP (Part V) for its distribution rate-setting purposes, and has transitioned to International Financial Reporting Standards beginning on January 1, 2015.

Transmission

In May 2012, Hydro One Networks filed a cost-of-service application with the OEB for 2013 and 2014 transmission rates. In December 2012, the OEB approved the 2013 and 2014 revenue requirement of $1,438 million and $1,528 million, respectively.

In December 2013, Hydro One Networks filed a draft Rate Order with the OEB for 2014 transmission rates. The 2014 transmission revenue requirement was increased to $1,535 million from the originally-approved revenue requirement of $1,528 million, primarily due to changes in the cost of capital parameters for 2014 released by the OEB in November 2013. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed.

Distribution

In June 2012, Hydro One Networks filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued its final Decision, which resulted in an increase in distribution rates of approximately 1.3% in 2013, or 0.4% when considering total bill impact, for a typical residential customer consuming 800 kWh per month. In April 2013, Hydro One Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. In December 2013, the OEB issued its final Decision, which resulted in an increase in distribution rates of approximately 2.4% in 2014, or 0.85% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

In August 2012, Hydro One Brampton Networks filed an IRM application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued its final Decision, which resulted in an increase in distribution rates of approximately 0.3% in 2013, or less than 0.1% when considering total bill impact, for a typical residential customer consuming 800 kWh per month. In August 2013, Hydro One Brampton Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. In December 2013, the OEB issued its final Decision, which resulted in a reduction in distribution rates of approximately 2.3% in 2014, or 0.5% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

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. In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 rates, seeking approval for a rate increase of approximately 0.5%. In March 2014, the OEB approved an increase of approximately 1.7% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2014. The final rate increase was adjusted by the OEB’s updated rate adjustment parameters and Hydro One Remote Communities’ IRM stretch factor.

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 final 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.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to the Shareholder of the parent company. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income (loss) and other comprehensive income (loss) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

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 judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

Current Income Taxes

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

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and 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 deferred income 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 company-wide 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%	4%
Administration and service	15 years	3% – 20%	7%

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 20%.

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, 2014, based on the qualitative assessment performed as at September 30, 2014, 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, 2014.

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, 2014, 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 issuance costs on the Consolidated Balance Sheets. Deferred debt issuance 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). 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. All financial instrument transactions are recorded at trade date.

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.

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 on 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 Statements 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 which 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, 2014 or 2013.

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 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 and the newly acquired Norfolk Power 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 the 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, 2013, OMERS had approximately 440,000 members, with approximately 335 members being current employees of Hydro One Brampton Networks and Norfolk Power.

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 and Norfolk Power 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 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 Company records a loss at the minimum amount within the range.

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

Provisions are based upon current estimates and are subject to greater uncertainty 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 July 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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. 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 May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This ASU provides guidance on revenue recognition that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company is currently assessing the impact of adoption of ASU 2014-09 on its consolidated financial statements.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This ASU provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and related disclosures. This ASU is effective for the annual period ending December 31, 2016, and for annual and interim periods thereafter. The adoption of this ASU is not anticipated to have a significant impact on the Company's consolidated financial statements.

In November 2014, the FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815). This ASU provides guidance on accounting for hybrid financial instruments issued in the form of a share. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The Company is currently assessing the impact of adoption of ASU 2014-16 on its consolidated financial statements.

4. BUSINESS COMBINATIONS

B2M Limited Partnership

In 2012, Hydro One entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively referred to as the Saugeen Ojibway Nation (SON), where a noncontrolling equity interest in Hydro One's new limited partnership, B2M LP, would be made available for purchase at fair value by the SON. B2M LP was formed by Hydro One in 2013 to hold most of the transmission lines and a licence to use the related land. These assets are associated with Hydro One's Bruce to Milton Transmission Reinforcement Project, an electricity transmission line (Bruce to Milton Line) in southwestern Ontario, from the Bruce Power facility in Kincardine to Hydro One's Milton Switching Station in the Town of Milton. Hydro One Networks will maintain and operate the Bruce to Milton Line in accordance with an operation and management services agreement. In November 2013, the OEB issued a Decision and Order granting B2M LP a transmission licence and granting Hydro One Networks leave to sell the relevant Bruce to Milton Line transmission assets to B2M LP.

On December 16, 2014, the relevant Bruce to Milton Line transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the SON acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired.

Part of the SON's equity interest in B2M LP is in Class B units of B2M LP that have a mandatory put option. The put option requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), the SON has the ability to require Hydro One to purchase the Class B units of B2M LP for net book value on the redemption date.

The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity. At December 31, 2014, the total noncontrolling interest was reduced by the 2014 net loss attributable to noncontrolling interest totalling $2 million, including $1 million relating to noncontrolling interest subject to redemption.

Acquisition of Norfolk Power

On August 29, 2014, Hydro One acquired 100% of the common shares of Norfolk Power, an electricity distribution and telecom company located in southwestern Ontario. The total purchase price for Norfolk Power, net of the long-term debt assumed and adjusted for preliminary working capital and other closing adjustments, is approximately $68 million.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Working capital	6
Property, plant and equipment	56
Deferred income tax assets	1
Goodwill	40
Bank indebtedness	(3)
Derivative instruments	(3)
Long-term debt	(26)
Post-retirement and post-employment benefit liability	(1)
Environmental liability	(1)
Long-term accounts payable and other liabilities	(1)
	68

The determination of the fair values of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. The purchase agreement provides for final purchase price adjustments based on agreed working capital and other balances at the acquisition date which have not yet been finalized. The Company will continue to review information and perform further analysis prior to finalizing the total purchase price and therefore the actual total purchase price and the consequent impact on goodwill may differ from the amounts above.

Goodwill of approximately $40 million arising from the Norfolk Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Norfolk Power. All of the goodwill was assigned to Hydro One's Distribution Business segment. None of the goodwill recognized is expected to be deductible for income tax purposes.

Norfolk Power contributed revenues of $18 million and net income of less than $1 million to the Company's consolidated financial results for the year ended December 31, 2014.

All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. The disclosure of Norfolk Power's pro forma information is immaterial to the Company's consolidated financial results for the year ended December 31, 2014.

Woodstock Hydro Purchase Agreement

On May 21, 2014, Hydro One reached an agreement with the City of Woodstock to acquire 100% of the common shares of Woodstock Hydro Holdings Inc. (Woodstock Hydro), an electricity distribution company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Woodstock Hydro will be approximately $29 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2015. In anticipation of the Woodstock Hydro acquisition, the Company made a refundable deposit totalling $2 million, which is recorded in prepaid expenses and other assets on the Consolidated Balance Sheet.

Haldimand Hydro Purchase Agreement

On June 10, 2014, Hydro One reached an agreement with Haldimand County to acquire 100% of the common shares of Haldimand County Utilities Inc. (Haldimand Hydro), an electricity distribution and telecom company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Haldimand Hydro will be approximately $65 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2015. In anticipation of the Haldimand Hydro acquisition, the Company made a refundable deposit totalling $3 million, which is recorded in prepaid expenses and other assets on the Consolidated Balance Sheet.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Depreciation of property, plant and equipment	565	533
Amortization of intangible assets	53	48
Asset removal costs	81	79
Amortization of regulatory assets	23	16
	722	676

6. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Interest on long-term debt	432	416
Other	12	9
Less: Interest capitalized on construction and development in progress	(49)	(51)
Gain on interest-rate swap agreements	(10)	(11)
Interest earned on investments	(6)	(3)
	379	360

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)	**2014**	**2013**
Income before provision for PILs	836	912
Canadian federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	222	242
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(72)	(72)
Pension contributions in excess of pension expense	(24)	(23)
Overheads capitalized for accounting but deducted for tax purposes	(15)	(14)
Interest capitalized for accounting but deducted for tax purposes	(13)	(13)
Environmental expenditures	(5)	(4)
Prior year’s adjustments	(4)	(8)
Non-refundable investment tax credits	(3)	(4)
Post-retirement and post-employment benefit expense in excess of cash payments	3	4
Other	(1)	(1)
Net temporary differences	(134)	(135)
Net permanent differences	1	2
Total provision for PILs	89	109

The major components of income tax expense are as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Current provision for PILs	79	111
Deferred provision (recovery) for PILs	10	(2)
Total provision for PILs	89	109
Effective income tax rate	10.63%	11.98%

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2014, $39 million due from the OEFC was included in due from related parties on the Consolidated Balance Sheet (2013 – $29 million).

At December 31, 2014, the total provision for PILs includes deferred provision for PILs of $10 million (2013 – deferred recovery of $2 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 basis of the Company's assets and liabilities. At December 31, 2014 and 2013, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	8	7
Environmental expenditures	4	5
Depreciation and amortization in excess of capital cost allowance	(4)	–
Other	(1)	(1)
Total deferred income tax assets	7	11
Less: current portion	–	–
	7	11

December 31 (millions of Canadian dollars)	**2014**	**2013**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,713)	(1,556)
Regulatory amounts that are not recognized for tax purposes	(140)	(144)
Partnership interest	(38)	–
Goodwill	(21)	(20)
Post-retirement and post-employment benefits expense in excess of cash payments	559	542
Environmental expenditures	59	66
Other	–	1
Total deferred income tax liabilities	(1,294)	(1,111)
Less: current portion	19	18
	(1,313)	(1,129)

During 2014 and 2013, there were no changes in the rate applicable to future taxes.

8. ACCOUNTS RECEIVABLE

December 31 (millions of Canadian dollars)	**2014**	**2013**
Accounts receivable – billed	496	268
Accounts receivable – unbilled	586	691
Accounts receivable, gross	1,082	959
Allowance for doubtful accounts	(66)	(36)
Accounts receivable, net	1,016	923

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2014 and 2013:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Allowance for doubtful accounts – January 1	(36)	(23)
Write-offs	24	24
Additions to allowance for doubtful accounts	(54)	(37)
Allowance for doubtful accounts – December 31	(66)	(36)

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2014 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	13,209	4,416	626	9,419
Distribution	9,076	3,225	320	6,171
Communication	1,100	615	56	541
Administration and Service	1,502	793	23	732
Easements	623	85	–	538
	25,510	9,134	1,025	17,401

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

Financing charges capitalized on property, plant and equipment under construction were $48 million in 2014 (2013 – $48 million).

10. INTANGIBLE ASSETS

December 31, 2014 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	573	303	3	273
Other	5	2	–	3
	578	305	3	276

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

Financing charges capitalized on intangible assets under development were $1 million in 2014 (2013 – $3 million). The estimated annual amortization expense for intangible assets is as follows: 2015 – $53 million; 2016 – $53 million; 2017 – $53 million; 2018 – $45 million; and 2019 – $31 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)	**2014**	**2013**
Regulatory assets:		
Deferred income tax regulatory asset	1,327	1,145
Pension benefit regulatory asset	1,236	845
Post-retirement and post-employment benefits	273	308
Environmental	239	266
Pension cost variance	90	80
DSC exemption	16	7
OEB cost assessment differential	12	9
Retail settlement variance accounts	11	–
Long-term project development costs	–	5
Other	27	18
Total regulatory assets	3,231	2,683
Less: current portion	31	47
	3,200	2,636
Regulatory liabilities:		
Rider 11	83	55
External revenue variance	54	81
CDM deferral variance account	25	–
Deferred income tax regulatory liability	21	19
PST savings deferral	19	17
Hydro One Brampton Networks rider	2	8
Retail settlement variance accounts	–	35
Rider 9	–	19
Other	11	14
Total regulatory liabilities	215	248
Less: current portion	47	85
	168	163

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 2014 provision for PILs would have been higher by approximately $132 million (2013 – $139 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, 2014 OCI would have been lower by $391 million (2013 – higher by $670 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, 2014 OCI would have been higher by $35 million (2013 – $12 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 2014, the environmental regulatory asset decreased by $33 million (2013 – $3 million) to reflect related changes in the Company's PCB liability, and increased by $13 million (2013 – $26 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, 2014 operation, maintenance and administration expenses would have been lower by $20 million (2013 – higher by $23 million). In addition, 2014 amortization expense would have been lower by $18 million (2013 – $16 million), and 2014 financing charges would have been higher by $11 million (2013 – $10 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 expenses 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, 2014 revenue would have been lower by $10 million (2013 – $19 million).

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 identified specific expenditures can be recorded in a deferral account subject to the OEB's review until the next Hydro One Networks' distribution cost-of-service application. This program effectively ended at the end of 2014 with no new principal to be recorded in 2015.

OEB Cost Assessment Differential

In April 2010, the OEB issued its Decision regarding Hydro One Networks' distribution 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. This continued for 2012-2014 until the next Hydro One Networks' distribution cost-of-service application, which was submitted in 2014. This program effectively ended at the end of 2014 with no new activity to be recorded in 2015.

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. At December 31, 2014, the RSVA was in a net asset position due to a change in global adjustment.

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 11

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. Rider 11 includes amounts previously included as Rider 8.

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.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 CDM compared to the amounts included in 2013 revenue requirement. The OEB rate order specifically states that the Ontario Power Authority (OPA) data used to calculate the difference between forecasted and actual savings will be provided one year in arrears, and as a result, no amount should be recorded in advance of notification from the OPA of actual results. This notification from the OPA typically occurs in September of each year.

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 administration 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, 2014 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 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.

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, 2014 and 2013.

Hydro One has a $1,500 million committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2019. 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, 2014, $1,187 million remained available for issuance until October 2015.

The following table presents the outstanding long-term debt at December 31, 2014 and 2013:

December 31 (millions of Canadian dollars)	**2014**	**2013**
3.13% Series 19 notes due 2014[1]	–	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	750
Floating-rate Series 31 notes due 2019[2]	228	–
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	435
4.17% Series 32 notes due 2044	350	–
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
4.29% Series 30 notes due 2064	50	–
	8,923	9,045
Add: Unrealized mark-to-market loss[1]	2	12
Less: Long-term debt payable within one year	(552)	(756)
Long-term debt	8,373	8,301

[1] The unrealized mark-to-market loss relates to $250 million of the Series 21 notes due 2015 (2013 – $500 million of the Series 19 notes due 2014, and $250 million of the Series 21 notes due 2015). The unrealized mark-to-market loss is offset by a $2 million (2013 – $12 million) unrealized mark-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 2014, Hydro One issued $628 million (2013 – $1,185 million) of long-term debt under the MTN Program, and repaid the $750 million MTN Series 19 notes (2013 – repaid $600 million MTN Series 15 notes). In addition, the Company repaid long-term debt totalling $26 million assumed on the Norfolk Power acquisition.

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, 2014 and 2013, 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, 2014 and 2013 are as follows:

December 31 (millions of Canadian dollars)	2014 Carrying Value	2014 Fair Value	2013 Carrying Value	2013 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	–	–	506	506
$250 million of MTN Series 21 notes[1]	252	252	256	256
Other notes and debentures[2]	8,673	10,159	8,295	9,018
	8,925	10,411	9,057	9,780

[1] The fair value of $500 million of the MTN Series 19 notes and 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).

[2] 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, 2014, the Company had interest-rate swaps totalling $250 million (2013 – $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 3% (2013 – 8%) of its total long-term debt of $8,925 million (2013 – $9,057 million). At December 31, 2014, the Company had the following interest-rate swaps designated as fair value hedges:

(a) 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, 2014, the Company also had interest-rate swaps with a total notional value of $409 million (2013 – $900 million) classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(b) a $150 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2014 to September 11, 2015;
(c) 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 22 notes from January 24, 2014 to January 24, 2015;

(d) a $137 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $228 million floating-rate MTN Series 31 notes from December 22, 2014 to December 21, 2015;

(e) a $30 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 3, 2015 to December 3, 2015;

(f) a $30 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 22 notes from January 26, 2015 to July 24, 2015; and

(g) three interest-rate swaps with a total notional value of $12 million that were assumed as part of the Norfolk Power acquisition. These swaps consist of $8 million and $2 million floating-to-fixed interest-rate swap agreements maturing on September 20, 2029, and a $2 million floating-to-fixed interest-rate swap agreement maturing on September 20, 2019.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2014 and 2013 is as follows:

December 31, 2014 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	100	100	100	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	–	2	–
	102	102	100	2	–
Liabilities:					
Bank indebtedness	2	2	2	–	–
Derivative instruments					
Undesignated contracts – interest-rate swaps	3	3	–	3	–
Long-term debt	8,925	10,411	–	10,411	–
	8,930	10,416	2	10,414	–

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	–

Cash and cash equivalents include cash and short-term investments. At December 31, 2014, short-term investments consisted of bankers' acceptances and money market funds totalling $nil (2013 – $515 million). The carrying values are representative of fair value because of the short-term nature of these instruments.

The investment at December 31, 2013 represented the Province of Ontario Floating-Rate Notes that matured in November 2014. The fair value of the investment was determined using inputs other than quoted prices that are observable for the asset, with unrecognized gains or losses recognized in financing charges. The Company obtained 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, 2014 and 2013.

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' 2014 annual results of operations by approximately $20 million (2013 – $19 million) and Hydro One Networks' distribution business' 2014 annual results of operations by approximately $10 million (2013 – $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, 2014 or 2013.

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, 2014 or 2013.

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, 2014 and 2013 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Unrealized loss (gain) on hedged debt	(3)	(8)
Unrealized loss (gain) on fair value interest-rate swaps	3	8
Net unrealized loss (gain)	–	–

At December 31, 2014, Hydro One had $250 million (2013 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $2 million (2013 – $12 million). During the years ended December 31, 2014 and 2013, 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, 2014 and 2013, 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, 2014 and 2013, there was no significant accounts receivable balance due from any single customer.

At December 31, 2014, the Company's provision for bad debts was $66 million (2013 – $36 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2014, approximately 6% of the Company's net accounts receivable were aged more than 60 days (2013 – 4%).

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 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, 2014, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $3 million (2013 – $14 million). At December 31, 2014, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with five financial institutions as the counterparties. The credit exposure of three of the five 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, and the revolving standby credit facility of $1,500 million. The short-term liquidity under the Commercial Paper Program, and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2014, accounts payable and accrued liabilities in the amount of $784 million (2013 – $789 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2014, Hydro One had issued long-term debt in the principal amount of $8,923 million (2013 – $9,045 million). Principal repayments, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	**Long-term Debt Principal Repayments** *(millions of Canadian dollars)*	**Interest Payments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	550	419	2.8
2 years	500	393	4.3
3 years	600	381	5.2
4 years	750	350	2.8
5 years	228	327	1.6
	2,628	1,870	3.5
6 – 10 years	900	1,522	3.6
Over 10 years	5,395	4,373	5.4
	8,923	7,765	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, 2014 and 2013, the Company's capital structure was as follows:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Long-term debt payable within one year	552	756
Less: cash and cash equivalents	100	565
	452	191
Long-term debt	8,373	8,301
Preferred shares	323	323
Common shares	3,314	3,314
Retained earnings	4,249	3,787
	7,563	7,101
Total capital	16,711	15,916

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, 2014 and 2013, 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 employees of Hydro One Brampton Networks and Norfolk Power. Employees of Hydro One Brampton Networks and Norfolk Power participate in the OMERS plan. 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, 2014 were $2 million (2013 – $2 million). Company contributions payable at December 31, 2014 and included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2013 – less than $1 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS plan, as indicated in OMERS' most recently available annual report for the year ended December 31, 2013.

At December 31, 2013, the OMERS plan was 88.2% funded, with an unfunded liability of $8,641 million. This unfunded liability could 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 2014 of $174 million (2013 – $160 million) were based on an actuarial valuation effective December 31, 2013 (2013 – effective December 31, 2011) and the expected level of pensionable earnings. Estimated annual Pension Plan contributions for 2015 and 2016 are approximately $174 million and $175 million, respectively, based on the actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

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)	**2014**	**2013**	**2014**	**2013**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	6,576	6,507	1,531	1,459
Current service cost	145	170	41	40
Interest cost	312	278	73	63
Reciprocal transfers	–	1	–	–
Benefits paid	(319)	(317)	(45)	(44)
Net actuarial loss (gain)	821	(63)	(18)	13
Projected benefit obligation, end of year	7,535	6,576	1,582	1,531
Change in plan assets				
Fair value of plan assets, beginning of year	5,731	4,992	–	–
Actual return on plan assets	703	887	–	–
Reciprocal transfers	–	1	–	–
Benefits paid	(319)	(317)	–	–
Employer contributions	174	160	–	–
Employee contributions	35	30	–	–
Administrative expenses	(25)	(22)	–	–
Fair value of plan assets, end of year	6,299	5,731	–	–
Unfunded status	1,236	845	1,582	1,531

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)	**2014**	**2013**	**2014**	**2013**
Accrued liabilities	–	–	49	43
Pension benefit liability	1,236	845	–	–
Post-retirement and post-employment benefit liability	–	–	1,533	1,488
Unfunded status	1,236	845	1,582	1,531

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)	**2014**	**2013**
PBO	7,535	6,576
ABO	6,887	5,998
Fair value of plan assets	6,299	5,731

On an ABO basis, the Pension Plan was funded at 91% at December 31, 2014 (2013 – 96%). On a PBO basis, the Pension Plan was funded at 84% at December 31, 2014 (2013 – 87%). 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, 2014 and 2013 for the Pension Plan:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Current service cost, net of employee contributions	110	141
Interest cost	312	278
Expected return on plan assets, net of expenses	(369)	(309)
Actuarial loss amortization	103	175
Prior service cost amortization	2	2
Net periodic benefit costs	158	287
Charged to results of operations[1]	81	72

[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, 2014, pension costs of $174 million (2013 – $160 million) were attributed to labour, of which $81 million (2013 – $72 million) was charged to operations, and $93 million (2013 – $88 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, 2014 and 2013 for the post-retirement and post-employment benefit plans:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Current service cost, net of employee contributions	41	40
Interest cost	73	63
Actuarial loss amortization	18	27
Prior service cost amortization	2	3
Net periodic benefit costs	134	133
Charged to results of operations	62	58

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 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, 2014 and 2013:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2014**	**2013**	**2014**	**2013**
Significant assumptions:				
Weighted average discount rate	4.00%	4.75%	4.00%	4.75%
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%
Rate of increase in health care cost trends[1]	–	–	4.36%	4.39%

[1] 6.52% per annum in 2015, grading down to 4.36% per annum in and after 2031 (2013 – 6.81% in 2014, 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, 2014 and 2013. 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	**2014**	**2013**
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.50%	6.25%
Weighted average discount rate	4.75%	4.25%
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	4.75%	4.25%
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)*	12	12
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 (2013 – 6.91% in 2013, grading down to 4.39% 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 a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2014 and 2013 is as follows:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	248	258
Effect of a 1% decrease in health care cost trends	(193)	(200)

The effect of a 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, 2014 and 2013 is as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	23	21
Effect of a 1% decrease in health care cost trends	(17)	(16)

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, 2014 and 2013:

December 31, 2014				**December 31, 2013**			
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	23	25	24	26

Estimated Future Benefit Payments

At December 31, 2014, estimated future benefit payments to the participants of the Plans were:

(millions of Canadian dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2015	305	50
2016	316	52
2017	328	54
2018	339	56
2019	350	59
2020 through to 2024	1,889	332
Total estimated future benefit payments through to 2024	3,527	603

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)	**2014**	**2013**
Pension Benefits:		
Actuarial loss (gain) for the year	511	(619)
Actuarial loss amortization	(103)	(175)
Prior service cost amortization	(2)	(2)
	406	(796)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	(18)	13
Actuarial loss amortization	(18)	(27)
Prior service cost amortization	(2)	(3)
	(38)	(17)

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, 2014 and 2013:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Pension Benefits:		
Prior service cost	2	3
Actuarial loss	1,234	842
	1,236	845
Post-Retirement and Post-Employment Benefits:		
Prior service cost	–	2
Actuarial loss	273	306
	273	308

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)	**2014**	**2013**	**2014**	**2013**
Prior service cost	2	2	–	2
Actuarial loss	119	103	10	15
	121	105	10	17

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension 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 Audit, Finance and Pension Investment 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, 2014, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	60.9
Debt securities	35.0	35.9
Other[1]	5.0	3.2
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2014, the Pension Plan held no Hydro One corporate bonds (2013 – $15 million) and $340 million of debt securities of the Province (2013 – $217 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, 2014 and 2013. 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, 2014 and 2013, 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 Rating Services Inc., DBRS Limited, and Fitch Ratings Inc., 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, 2014 and 2013:

December 31, 2014 (millions of Canadian dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	–	18	142	160
Cash and cash equivalents	166	–	–	166
Short-term securities	–	176	–	176
Real estate	–	–	2	2
Corporate shares – Canadian	1,008	–	–	1,008
Corporate shares – Foreign	2,766	–	–	2,766
Bonds and debentures – Canadian	–	1,799	–	1,799
Bonds and debentures – Foreign	–	211	–	211
Total fair value of plan assets[1]	3,940	2,204	144	6,288

[1] At December 31, 2014, the total fair value of Pension Plan assets excludes $18 million of interest and dividends receivable, and $7 million relating to accruals for pension administration expense.

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.

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, 2014 and 2013. 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)	**2014**	**2013**
Fair value, beginning of year	119	106
Realized and unrealized gains	30	23
Purchases	23	–
Sales and disbursements	(28)	(10)
Fair value, end of year	144	119

There were no significant transfers between any of the fair value levels during the years ended December 31, 2014 and 2013.

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 and infrastructure 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. Infrastructure investments represent infrastructure funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity and infrastructure 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 and infrastructure 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, 2014 and 2013:

Year ended December 31, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	201	65	266
Interest accretion	9	2	11
Expenditures	(5)	(13)	(18)
Revaluation adjustment	(33)	13	(20)
Environmental liabilities, December 31	172	67	239
Less: current portion	8	10	18
	164	57	221

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

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, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	195	70	265
Less: discounting accumulated liabilities to present value	23	3	26
Discounted environmental liabilities	172	67	239

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

At December 31, 2014, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2015	18
2016	37
2017	36
2018	35
2019	33
Thereafter	106
	265

At December 31, 2014, of the total estimated future environmental expenditures, $195 million relates to PCBs (2013 – $237 million) and $70 million relates to LAR (2013 – $68 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 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.

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 2.3% 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.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act,* 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. 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 $195 million. These expenditures are expected to be incurred over the period from 2015 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2014 to reduce the PCB environmental liability by $33 million (2013 – $3 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $70 million. These expenditures are expected to be incurred over the period from 2015 to 2023. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2014 to increase the LAR environmental liability by $13 million (2013 – $26 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, 2014, Hydro One had recorded AROs of $9 million (2013 – $14 million), consisting of $8 million (2013 – $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 $1 million (2013 – $7 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal.

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 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, 2014. 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

Basic and diluted earnings per share have been calculated on the basis of net income attributable to the Shareholder of Hydro One and the weighted average number of common shares outstanding during the year.

19. DIVIDENDS

In 2014, preferred share dividends in the amount of $18 million (2013 – $18 million) and common share dividends in the amount of $269 million (2013 – $200 million) were declared.

20. RELATED PARTY TRANSACTIONS

Hydro One is owned by the Province. The OEFC, IESO, 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.

The Province

During 2014, Hydro One paid dividends to the Province totalling $287 million (2013 – $218 million).

In November 2014, the Company redeemed the $250 million Province of Ontario Floating-Rate Notes held as a long-term investment. These notes were originally purchased in January 2010 with a maturity date of November 19, 2014.

IESO

In 2014, Hydro One purchased power in the amount of $2,601 million (2013 – $2,477 million) from the IESO-administered electricity market.

Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues for 2014 include $1,556 million (2013 – $1,509 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues for 2014 include $127 million (2013 – $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 for 2014 include $32 million (2013 – $33 million) related to these services.

OPA

The OPA funds substantially all of the Company’s conservation and demand management programs. The funding includes program costs, incentives, and management fees. In 2014, Hydro One received $33 million (2013 – $34 million) from the OPA related to these programs.

OPG

In 2014, Hydro One purchased power in the amount of $23 million (2013 – $15 million) from OPG.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2014, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $12 million (2013 – $9 million), primarily for the Transmission Business. Operation, maintenance and administration costs in 2014 related to the purchase of services with respect to these service level agreements were $1 million (2013 – $1 million).

OEFC

In 2014, Hydro One made payments in lieu of corporate income taxes to the OEFC totalling $86 million (2013 – $138 million).

In 2014, Hydro One purchased power in the amount of $9 million (2013 – $8 million) from power contracts administered by the OEFC.

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.

OEB

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 2014, Hydro One incurred $12 million (2013 – $12 million) in OEB fees.

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.

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)	**2014**	**2013**
Due from related parties	224	197
Due to related parties[1]	(227)	(230)
Investment	–	251

[1] Included in due to related parties at December 31, 2014 are amounts owing to the IESO in respect of power purchases of $214 million (2013 – $217 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)	**2014**	**2013**
Accounts receivable	(93)	(78)
Due from related parties	(27)	(43)
Prepaid expenses and other assets	(13)	(5)
Accounts payable	39	13
Accrued liabilities	(35)	71
Due to related parties	(3)	(31)
Accrued interest	–	5
Long-term accounts payable and other liabilities	(3)	(5)
Post-retirement and post-employment benefit liability	80	84
	(55)	11

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 capitalized depreciation and the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Capital investments in property, plant and equipment	(1,511)	(1,312)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	30	4
Capital expenditures – property, plant and equipment	(1,481)	(1,308)

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)	**2014**	**2013**
Capital investments in intangible assets	(19)	(82)
Net change in accruals included in capital investments in intangible assets	(4)	3
Capital expenditures – intangible assets	(23)	(79)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Net interest paid	412	395
PILs	86	138

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 2014, the Company paid approximately $1 million (2013 – $2 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

Outsourcing Agreements

The current agreement with Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., expires on February 28, 2015. On November 28, 2014, Hydro One entered into an agreement with Inergi (Inergi Agreement), the service provider selected through a competitive procurement process which began in 2013, for second-generation back office and IT outsourcing services for a term of 58 months, commencing March 1, 2015 to December 31, 2019. Under the agreement, Inergi will provide Hydro One with settlements, source to pay services, pay operations services, information technology and finance and accounting services. Coincident with the conclusion of negotiations on the Inergi Agreement, Hydro One reached agreement with Inergi for the provision of second-generation customer service operations outsourcing services for a fixed period of three years beginning March 1, 2015 to February 28, 2018.

In September 2014, Hydro One entered into an agreement with Brookfield Johnson Controls Canada LP (Brookfield) for facilities management services for a term of ten years, from January 1, 2015 to December 31, 2024, with the option to renew for an additional term of three years. Under the agreement, Brookfield will provide us with facilities management and execution of certain capital projects as deemed required by the Company. The Brookfield Agreement has a value of up to approximately $658 million over the ten-year term of the agreement, including the facilities management portion of the contract, plus a variable amount of capital work depending on the needs that may arise as determined by the Company, with no minimum capital work guarantee. The agreement also includes a fixed management fee of approximately $2 million for each year of the term.

At December 31, 2014, the annual commitments under the outsourcing agreements were as follows: 2015 – $179 million; 2016 – $146 million; 2017 – $145 million; 2018 – $113 million; 2019 – $105 million; and thereafter – $13 million.

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, 2014, the Company provided prudential support to the IESO on behalf of its subsidiaries using parental guarantees of $330 million (2013 – $325 million), and on behalf of two distributors using guarantees of $1 million (2013 – $1 million). In addition, as at December 31, 2014, the Company has provided letters of credit in the amount of $8 million (2013 – $21 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, 2014, Hydro One had letters of credit of $126 million (2013 – $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 a typical term of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. 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 or pre-established rents. 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.

During the year ended December 31, 2014, the Company made lease payments totalling $11 million (2013 – $11 million). At December 31, 2014, the future minimum lease payments under non-cancellable operating leases were as follows: 2015 – $7 million; 2016 – $10 million; 2017 – $9 million; 2018 – $7 million; 2019 – $3 million; and thereafter – $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, which includes certain corporate activities and the operations 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, 2014 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	1,588	4,903	57	6,548
Purchased power	–	3,419	–	3,419
Operation, maintenance and administration	394	742	56	1,192
Depreciation and amortization	346	367	9	722
Income (loss) before financing charges and provision for PILs	848	375	(8)	1,215
Capital investments	845	680	5	1,530

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
Capital investments	714	673	7	1,394

Total Assets by Segment:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Transmission	12,540	11,846
Distribution	9,805	8,805
Other	205	974
Total assets	22,550	21,625

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

25. SUBSEQUENT EVENT

On February 11, 2015, preferred share dividends in the amount of $4 million and common share dividends in the amount of $25 million were declared.

HYDRO ONE NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2014

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying carve-out financial statements of the Transmission Business (a business of Hydro One Networks Inc.), which comprise the carve-out balance sheet as at December 31, 2014, the carve-out 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 carve-out financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Management's Responsibility for the Carve-out Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these carve-out financial statements in accordance with the basis of accounting in Note 2 to the carve-out financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of carve-out 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 carve-out 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 carve-out financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the carve-out financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the carve-out financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation of the carve-out 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 carve-out 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 carve-out financial statements as at and for the year ended December 31, 2014 are prepared, in all material respects, in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to the carve-out financial statements, which describes the basis of preparation used in these carve-out financial statements. In particular, in preparing the carve-out financial statements, long-term debt, shared functions and service costs, and payments in lieu of corporate income taxes have been allocated to the Transmission Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to the carve-out financial statements. As a result, the carve-out financial statements may not necessarily be identical to the balance sheet, results of operations and cash flows that would have resulted had the Transmission Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. The carve-out financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, the carve-out financial statements may not be suitable for another purpose.

Our report is intended solely for the Directors of 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 24, 2015

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Revenues		
Transmission tariff *(Note 17)*	1,549	1,493
Other	38	36
	1,587	1,529
Costs		
Operation, maintenance and administration *(Note 17)*	400	388
Depreciation and amortization *(Note 4)*	346	326
	746	714
Income before financing charges and provision for payments in lieu of corporate income taxes	841	815
Financing charges *(Notes 5, 17)*	222	215
Income before provision for payments in lieu of corporate income taxes	619	600
Provision for payments in lieu of corporate income taxes *(Notes 6, 17)*	87	79
Net income	532	521
Other comprehensive income	–	–
Comprehensive income	532	521

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS
At December 31, 2014 and 2013

December 31 (millions of Canadian dollars)	**2014**	**2013**
Assets		
Current assets:		
Inter-company demand facility *(Notes 11, 12, 17)*	234	325
Accounts receivable (net of allowance for doubtful accounts – $1; 2013 – $2) (Notes 17)	178	192
Materials and supplies	13	13
Regulatory assets *(Note 9)*	18	28
Deferred income tax assets *(Note 6)*	10	10
Derivative instruments *(Note 11)*	1	2
Other	8	8
	462	578
Property, plant and equipment *(Note 7)*		
Property, plant and equipment in service	14,467	14,140
Less: accumulated depreciation	5,202	4,951
	9,265	9,189
Construction in progress	667	737
Future use land, components and spares	94	91
	10,026	10,017
Other long-term assets:		
Regulatory assets *(Note 9)*	1,106	1,066
Intangible assets (net of accumulated amortization – $123; 2013 – $104) *(Note 8)*	107	116
Deferred debt costs	22	22
Derivative instruments *(Note 11)*	–	3
Other	2	–
	1,237	1,207
Total assets	11,725	11,802

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS (continued)
At December 31, 2014 and 2013

December 31 (millions of Canadian dollars)	**2014**	**2013**
Liabilities		
Current liabilities:		
Accounts payable	85	60
Accrued liabilities *(Notes 6, 13, 14, 17)*	166	219
Accrued interest *(Note 17)*	60	61
Regulatory liabilities *(Note 9)*	32	55
Long-term debt payable within one year *(Notes 10, 11, 12, 17)*	331	327
	674	722
Long-term debt *(Notes 10, 11, 12, 17)*	4,986	4,954
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 13)*	649	636
Deferred income tax liabilities *(Note 6)*	874	806
Environmental liabilities *(Note 14)*	86	89
Regulatory liabilities *(Note 9)*	58	43
Net unamortized debt premiums	9	9
Asset retirement obligations *(Note 15)*	4	10
Long-term accounts payable and other liabilities	13	8
	1,693	1,601
Total liabilities	7,353	7,277
Contingencies and commitments (Notes 19, 20)		
Excess of assets over liabilities *(Notes 12, 16)*	4,372	4,525
Total liabilities and excess of assets over liabilities	11,725	11,802

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Carmine Marcello
Chair

Ali R. Suleman
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Operating activities		
Net income	532	521
Environmental expenditures	(6)	(6)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	319	301
Regulatory assets and liabilities	1	14
Deferred income taxes	1	(5)
Other	(2)	7
Changes in non-cash balances related to operations *(Note 18)*	26	48
Net cash from operating activities	871	880
Financing activities		
Long-term debt issued	365	652
Long-term debt retired	(325)	(370)
Payments to Hydro One Inc. to finance dividends	(685)	(108)
Other	(2)	(3)
Net cash from (used in) financing activities	(647)	171
Investing activities		
Capital expenditures *(Note 18)*		
Property, plant and equipment	(834)	(710)
Intangible assets	(4)	(4)
Proceeds from transfer of assets	526	–
Other	(3)	–
Net cash used in investing activities	(315)	(714)
Net change in inter-company demand facility	(91)	337
Inter-company demand facility, beginning of year	325	(12)
Inter-company demand facility, end of year	234	325

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 transmission business (Transmission Business) operates a high-voltage electrical transmission network that represents almost all of the licensed transmission capacity in Ontario. The Transmission 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, 2014 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 Transmission 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 Transmission 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 Transmission 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 Transmission 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 Transmission 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 Transmission 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 through to March 24, 2015, 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 21 – 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 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), 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 Transmission Business beginning with the year 2012.

In May 2012, Hydro One Networks filed a cost-of-service application with the OEB for 2013 and 2014 transmission rates. In December 2012, the OEB approved the 2013 and 2014 revenue requirement of $1,438 million and $1,528 million, respectively.

In December 2013, Hydro One Networks filed a draft Rate Order with the OEB for 2014 transmission rates. The 2014 transmission revenue requirement was increased to $1,535 million from the originally-approved revenue requirement of $1,528 million, primarily due to changes in the cost of capital parameters for 2014 released by the OEB in November 2013. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed.

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 Transmission 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 Transmission Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Transmission 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 Transmission 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

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. 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. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Transmission 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 Transmission 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. At December 31, 2014 and 2013, the allowance for doubtful accounts was entirely related to non-energy receivables.

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

The Transmission 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 Transmission 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 transmission, 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.

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 Transmission 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	Average
Transmission	57 years	1% – 2%	2%
Communication	20 years	1% – 5%	4%
Administration and service	15 years	6% – 20%	6%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software assets are approximately 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 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.

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 Transmission 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 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. All financial instrument transactions are recorded at trade date.

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 11 – Fair Value of Financial Instruments and Risk Management.

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, 2014.

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, 2014, 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, 2014.

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, 2014.

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 Transmission 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 Transmission 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 Transmission 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 Transmission 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 transmission 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 Transmission 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 Transmission 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 July 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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. The adoption of this ASU did not have a significant impact on the Transmission Business’ financial statements.

Recent Accounting Guidance Not Yet Adopted

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This ASU provides guidance on revenue recognition that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Transmission Business is currently assessing the impact of adoption of ASU 2014-09 on its financial statements.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This ASU provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and related disclosures. This ASU is effective for the annual period ending December 31, 2016, and for annual and interim periods thereafter. The adoption of this ASU is not anticipated to have a significant impact on the Transmission Business' financial statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Depreciation of property, plant and equipment	289	274
Amortization of intangible assets	19	21
Asset removal costs	27	25
Amortization of regulatory assets	11	6
	346	326

5. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Interest on long-term debt *(Note 17)*	255	247
Other	6	6
Less: Interest capitalized on construction and development in progress	(31)	(33)
Gain on interest-rate swap agreements	(3)	(4)
Interest earned on inter-company demand facility *(Note 17)*	(5)	(1)
	222	215

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)	**2014**	**2013**
Income before provision for PILs	619	600
Canadian Federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	164	159
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(38)	(44)
Pension contributions in excess of pension expense	(12)	(13)
Interest capitalized for accounting but deducted for tax purposes	(9)	(9)
Overheads capitalized for accounting but deducted for tax purposes	(9)	(8)
Prior year's adjustments	(2)	(3)
Environmental expenditures	(2)	(2)
Non-refundable ITCs	(1)	(1)
Post-retirement and post-employment benefit expense in excess of cash payments	–	1
Other	(5)	(2)
Net temporary differences	(78)	(81)
Net permanent differences	1	1
Total provision for PILs	87	79
Current provision for PILs	86	84
Deferred provision for (recovery of) PILs	1	(5)
Total provision for PILs	87	79
Effective income tax rate	14.01%	13.17%

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2014, $17 million payable to the OEFC was included in accrued liabilities on the Balance Sheet (December 31, 2013 – receivable of $8 million included in accounts receivable).

The total provision for PILs includes deferred provision for PILs of $1 million (2013 – recovery of $5 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)	**2014**	**2013**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,080)	(1,003)
Regulatory amounts not recognized for tax	(48)	(54)
Post-retirement and post-employment benefits expense in excess of cash payments	242	236
Environmental expenditures	24	24
Other	(2)	1
Total deferred income tax liabilities	(864)	(796)
Less: current portion	10	10
	(874)	(806)

During 2014 and 2013, there was no change in the rate applicable to future taxes.

7. PROPERTY, PLANT AND EQUIPMENT

December 31, 2014 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	12,630	4,390	607	8,847
Communication	837	490	47	394
Administration and Service	481	241	13	253
Easements	613	81	–	532
	14,561	5,202	667	10,026

December 31, 2013 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	12,395	4,211	671	8,855
Communication	806	453	44	397
Administration and Service	421	213	22	230
Easements	609	74	–	535
	14,231	4,951	737	10,017

Financing charges capitalized on property, plant and equipment under construction were $31 million (2013 – $33 million).

8. INTANGIBLE ASSETS

December 31, 2014 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	224	120	2	106
Other	4	3	–	1
	228	123	2	107

December 31, 2013 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	214	101	2	115
Other	4	3	–	1
	218	104	2	116

Financing charges capitalized on intangible assets under development were immaterial in 2014 and 2013. The estimated annual amortization expense for intangible assets is as follows: 2015 – $20 million; 2016 – $20 million; 2017 – $20 million; 2018 – $16 million; and 2019 – $8 million.

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. The Transmission Business has recorded the following regulatory assets and liabilities:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Regulatory assets:		
Deferred income tax regulatory assets	903	835
Post-retirement and post-employment benefits	119	133
Environmental	91	100
Pension cost variance	11	21
Long-term project development costs	–	5
Total regulatory assets	1,124	1,094
Less: current portion	18	28
	1,106	1,066
Regulatory liabilities:		
External revenue variance	54	81
CDM deferral variance account	25	–
Deferred income tax regulatory liability	8	7
PST savings deferral	–	3
Other	3	7
Total regulatory liabilities	90	98
Less: current portion	32	55
	58	43

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 Transmission 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 Transmission 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 2014 provision for PILs would have been higher by approximately $50 million (2013 – $84 million).

Post-Retirement and Post-Employment Benefits

The Transmission 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, 2014 OCI would have been higher by $14 million (2013 – $6 million).

Environmental

The Transmission 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 2014, the environmental regulatory asset decreased by $8 million (2013 – $nil) to reflect related changes in the PCB liability, and increased by $1 million (2013 – $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 the Transmission Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2014 operation, maintenance and administration expenses would have been lower by $7 million (2013 – higher by $5 million). In addition, 2014 amortization expense would have been lower by $6 million (2013 – $6 million), and 2014 financing charges would have been higher by $4 million (2013 – $4 million).

Pension Cost Variance

A pension cost variance account was established for the Transmission 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, 2014 revenue would have been higher by $10 million (2013 – lower by $7 million).

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.

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 revenue. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, the Company agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 CDM compared to the amounts included in 2013 revenue requirement. The OEB rate order specifically states that the Ontario Power Authority (OPA) data used to calculate the difference between forecasted and actual savings will be provided one year in arrears, and as a result, no amount should be recorded in advance of notification from the OPA of actual results. This notification from the OPA typically occurs in September of each year.

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 Transmission Business, PST was included in rates between July 1, 2010 and December 31, 2014 and recorded in a deferral account per direction from the OEB.

10. 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 Transmission Business as at December 31, 2014 and 2013:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Long-term debt	5,316	5,276
Add: Unrealized marked-to-market loss[1]	1	5
Less: Long-term debt payable within one year	(331)	(327)
Long-term debt	4,986	4,954

[1] The unrealized marked-to-market loss relates to $150 million of Transmission Business' $300 million note due 2015 (2013 – $150 million of Transmission Business' $325 million note due 2014 and $150 million of Transmission Business' $300 million note due 2015). The unrealized marked-to-market loss is offset by a $1 million (2013 – $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 11 – 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 11 – Fair Value of Financial Instruments and Risk Management.

11. 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, 2014 and 2013, 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 Transmission Business's long-term debt at December 31, 2014 and 2013 are as follows:

December 31 (millions of Canadian dollars)	2014 Carrying Value	2014 Fair Value	2013 Carrying Value	2013 Fair Value
Long-term debt				
$150 million of $325 million notes due 2014[1]	–	–	152	152
$150 million of $300 million notes due 2015[1]	151	151	153	153
Other notes and debentures[2]	5,166	6,040	4,976	5,397
	5,317	6,191	5,281	5,702

[1] The fair value of $150 million of Transmission Business' $325 million notes due 2014 and $150 million of Transmission Business' $300 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).

[2] The fair value of other notes and debentures, and the portions of Transmission Business' $325 million and $300 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, 2014, the Transmission Business' share of the Company's derivative instruments include $150 million (2013 – $300 million) of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These interest-rate swaps are classified as fair value hedges. The Transmission Business' fair value hedge exposure was equal to about 3% (2013 – 6%) of its long-term debt. At December 31, 2014, the Transmission Business' interest-rate swaps designated as fair value hedges were as follows:

- two $75 million fixed-to-floating interest-rate swap agreements to convert $150 million of the $300 million notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2014, the Transmission Business' share of interest-rate swaps classified as undesignated contracts consisted of the following:

- a $150 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2014 to September 11, 2015;

- a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $30 million floating-rate MTN Series 22 notes from January 24, 2014 to January 24, 2015;
- a $137 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $137 million floating-rate MTN Series 31 notes from December 22, 2014 to December 21, 2015;
- a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $30 million floating-rate MTN Series 27 notes from March 3, 2015 to December 3, 2015; and
- a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $30 million floating-rate MTN Series 22 notes from January 26, 2015 to July 24, 2015.

Fair Value Hierarchy

Fair value hierarchy information for financial assets and liabilities at December 31, 2014 and 2013 was as follows:

December 31, 2014 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	234	234	234	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	1	1	–	1	–
	235	235	234	1	–
Liabilities:					
Long-term debt	5,317	6,191	–	6,191	–
	5,317	6,191	–	6,191	–

December 31, 2013 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	325	325	325	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	5	5	–	5	–
	330	330	325	5	–
Liabilities:					
Long-term debt	5,281	5,702	–	5,702	–
	5,281	5,702	–	5,702	–

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, 2014 and 2013.

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 Transmission 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 Transmission Business' rate of return would reduce the Transmission Business' 2014 results of operations by approximately $20 million (2013 – $19 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, 2014 or 2013.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in the Transmission Business' results of operations for the years ended December 31, 2014 or 2013.

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 Transmission Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2014 and 2013 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Unrealized loss (gain) on hedged debt	(2)	(3)
Unrealized loss (gain) on fair value interest-rate swaps	2	3
Net unrealized loss (gain)	–	–

At December 31, 2014, the amount of the Transmission Business' fair value hedges outstanding related to interest-rate swaps was $150 million (2013 – $300 million), with assets at fair value of $1 million (2013 – $5 million). During the years ended December 31, 2014 and 2013, there was no significant impact on the Transmission 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, 2014 and 2013, there were no significant concentrations of credit risk with respect to any class of financial assets. The Transmission Business did not earn a significant amount of revenue from any individual customer. At December 31, 2014 and 2013, there was no significant accounts receivable balance due from any single customer.

At December 31, 2014, the Transmission Business' allowance for doubtful accounts was $1 million (2013 – $2 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2014, approximately 1% of the Transmission Business' net accounts receivable were aged more than 60 days (2013 – $nil).

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 Transmission 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, 2014, accounts payable and accrued liabilities in the amount of $251 million (2013 – $279 million) were expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2014, the principal amount of the Transmission Business' long-term debt was $5,316 million (2013 – $5,276 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	330	251	2.9
2 years	300	235	4.4
3 years	405	228	5.2
4 years	412	207	2.8
5 years	137	194	1.7
	1,584	1,115	3.6
6 – 10 years	499	906	3.7
Over 10 years	3,233	2,641	5.4
	5,316	4,662	4.7

12. CAPITAL MANAGEMENT

The Transmission Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB.

The Transmission 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)	**2014**	**2013**
Long-term debt payable within one year	331	327
Inter-company demand facility	(234)	(325)
	97	2
Long-term debt	4,986	4,954
Excess of assets over liabilities	4,372	4,525
Total capital	9,455	9,481

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2014 and 2013:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Excess of assets over liabilities, January 1	4,525	4,112
Net income	532	521
Payments to Hydro One to finance dividends	(685)	(108)
Excess of assets over liabilities, December 31	4,372	4,525

13. 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 2014 of $174 million (2013 – $160 million) were based on an actuarial valuation effective December 31, 2013 (2013 – effective December 31, 2011) and the level of 2014 pensionable earnings. Estimated annual Pension Plan contributions for 2015 and 2016 are approximately $174 million and $175 million, respectively, based on an actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

At December 31, 2014, based on the December 31, 2013 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,535 million (2013 – $6,576 million). The fair value of pension plan assets available for these benefits was $6,299 million (2013 – $5,731 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2014, the Transmission Business charged $20 million (2013 – $20 million) of post-retirement and post-employment benefit costs to operations, and capitalized $30 million (2013 – $36 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2014 were $19 million (2013 – $19 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $14 million (2013 – $6 million).

The Transmission 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)	**2014**	**2013**
Accrued liabilities	24	20
Post-retirement and post-employment benefit liability	649	636
	673	656

14. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2014 and 2013:

Year ended December 31, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	84	16	100
Interest accretion	4	–	4
Expenditures	(3)	(3)	(6)
Revaluation adjustment	(8)	1	(7)
Environmental liabilities, December 31	77	14	91
Less: current portion	2	3	5
	75	11	86

Year ended December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	81	16	97
Interest accretion	3	1	4
Expenditures	–	(6)	(6)
Revaluation adjustment	–	5	5
Environmental liabilities, December 31	84	16	100
Less: current portion	8	3	11
	76	13	89

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, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	87	15	102
Less: discounting accumulated liabilities to present value	10	1	11
Discounted environmental liabilities	77	14	91

December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	101	17	118
Less: discounting accumulated liabilities to present value	17	1	18
Discounted environmental liabilities	84	16	100

At December 31, 2014, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2015	5
2016	16
2017	15
2018	14
2019	13
Thereafter	39
	102

At December 31, 2014, of the total estimated future environmental expenditures, $87 million relates to PCBs (2013 – $101 million) and $15 million relates to LAR (2013 – $17 million).

The Transmission 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 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.

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 3.8 % to 5.1%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission 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.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act,* 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, the Company's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. 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 Transmission Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $87 million. These expenditures are expected to be incurred over the period from 2015 to 2024. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2014 to reduce the PCB environmental liability by $8 million (2013 – $nil).

LAR

The Transmission Business' best estimate of the total estimated future expenditures to complete its LAR program is $15 million. These expenditures are expected to be incurred over the period from 2015 to 2022. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2014 to increase the LAR environmental liability by $1 million (2013 – $5 million).

15. 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 Transmission 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, 2014, the Company had recorded AROs of $4 million (2013 – $10 million), related to its Transmission 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.

16. 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 Transmission Business makes payments to finance its share of the Company's common share and preferred share dividends. During 2014, the Transmission Business' payments to finance these dividends totaled $685 million (2013 – $108 million).

17. RELATED PARTY TRANSACTIONS

The Transmission Business is a separately regulated business of Hydro One Networks which is 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 Transmission Business because they are controlled or significantly influenced by the Province. Transactions between these parties and the Transmission Business are described below.

IESO

The Transmission Business receives amounts for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Amounts received for the year ended December 31, 2014 were $1,555 million (2013 – $1,509 million). Consistent with the Company's revenue recognition policy, the Transmission Business recognized $1,549 million (2013 – $1,493 million) related to these services.

OPG

The Company has service level agreements with OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. In 2014, revenues of the Transmission Business related to the provision of construction and equipment maintenance services with respect to these service level agreements were $11 million (2013 – $8 million). Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were less than $1 million in both 2014 and 2013.

OEFC

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 Transmission Business' allocation of this fee is $4 million.

PILs and payments in lieu of property taxes were paid or payable to the OEFC.

OEB

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 2014, the Transmission Business incurred $5 million (2013 – $5 million) in OEB fees.

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)	**2014**	**2013**
Accounts receivable	135	140
Accrued liabilities	(25)	(6)

Hydro One and Subsidiaries

The Transmission 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. 2014 revenues of the Transmission Business include $3 million (2013 – $3 million) related to the provision of services to Hydro One and its subsidiaries. During year ended December 31, 2014, the Transmission Business provided services to Hydro One and its other subsidiaries totalling $31 million (2013 – $17 million), of which $20 million (2013 - $17 million) was charged to operation, maintenance and administration costs, and $11 million (2013 – $nil) was capitalized.

The Transmission 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 $255 million (2013 – $247 million), and interest income on the inter-company demand facility in the amount of $5 million (2013 –$1 million). At December 31, 2014, the Transmission Business had accrued interest payable to Hydro One totalling $60 million (2013 – $61 million).

On December 16, 2014, transmission assets totalling $526 million were transferred from Hydro One Networks' Transmission Business to B2M LP, a limited partnership between Hydro One and the Saugeen Ojibway Nation, for proceeds of $526 million. These assets are associated with an electricity transmission line (Bruce to Milton Line) in southwestern Ontario, from the Bruce Power facility in Kincardine to our Milton Switching Station in the Town of Milton. The Transmission Business of Hydro One Networks will maintain and operate the Bruce to Milton Line in accordance with an operation and management services agreement. No gain or loss was recognized due to the transfer of Bruce to Milton Line transmission assets being a common control transaction as Hydro One controlled these assets before and after the transfer.

During 2014, Hydro One Networks paid preferred share dividends in the amount of $20 million (2013 – $20 million) and common share dividends in the amount of $724 million (2013 – $200 million) to Hydro One. The amount allocated to the Transmission Business to finance these dividends was $685 million (2013 – $108 million).

18. 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)	**2014**	**2013**
Accounts receivable	14	(36)
Other assets	(2)	(1)
Accounts payable	28	4
Accrued liabilities	(45)	38
Accrued interest	(1)	3
Long-term accounts payable and other liabilities	5	2
Post-retirement and post-employment benefit liability	27	38
	26	48

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 capitalized depreciation and the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Capital investments in property, plant and equipment	(845)	(706)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	11	(4)
Capital expenditures – property, plant and equipment	(834)	(710)

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)	**2014**	**2013**
Capital investments in intangible assets	–	(8)
Net change in accruals included in capital investments in intangible assets	(4)	4
Capital expenditures – intangible assets	(4)	(4)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Net interest paid	251	241
PILs	62	88

19. CONTINGENCIES

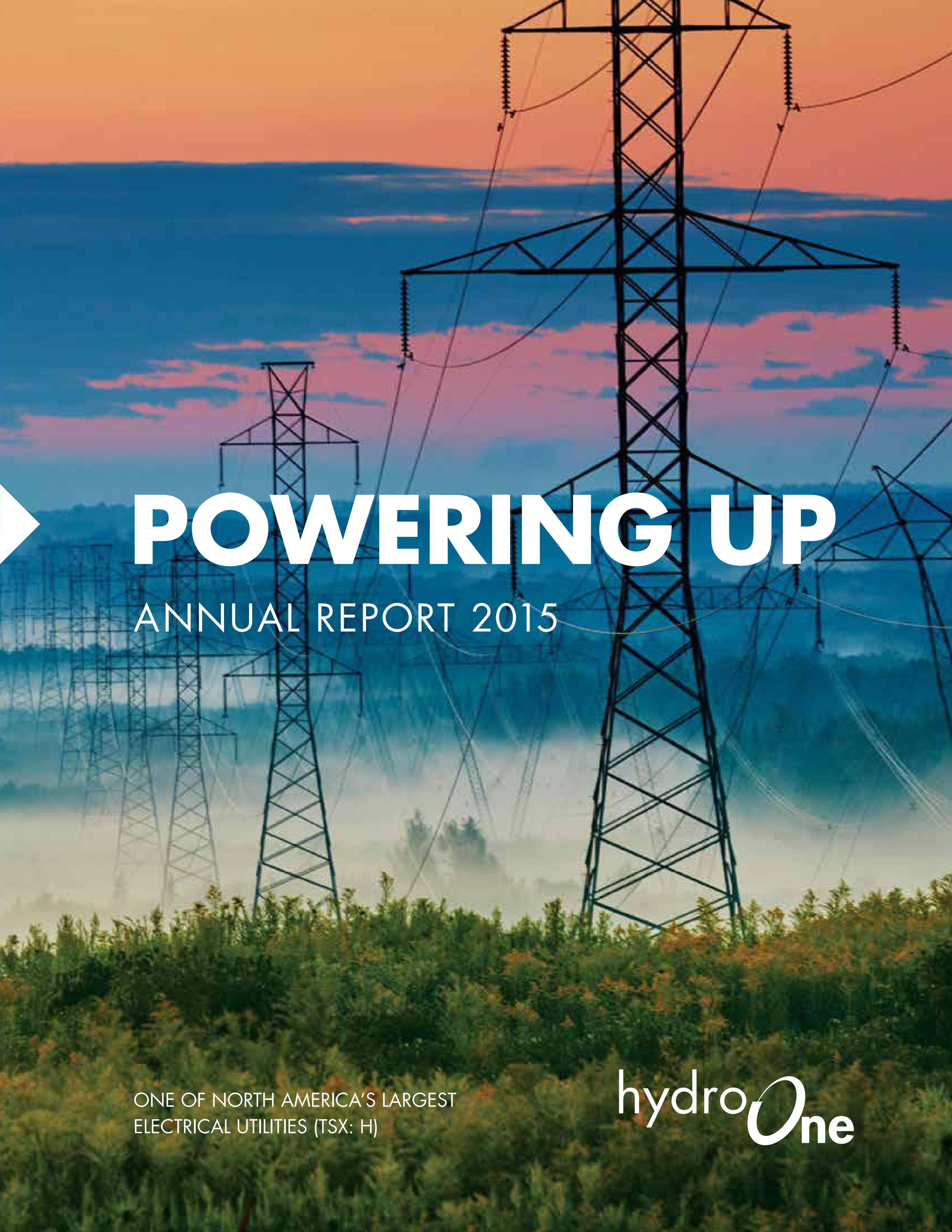
The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Transmission Business are available for the satisfaction of the debts, contingent liabilities and commitments of both the Company and Hydro One.

20. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Transmission Business. However, the net assets of the Transmission Business are available to satisfy the commitments of both the Company and Hydro One.

21. SUBSEQUENT EVENT

On February 11, 2015, Hydro One Networks declared preferred share dividends in the amount of $5 million and common share dividends in the amount of $25 million. The amount allocated to the Transmission Business to finance these dividends was $28 million.



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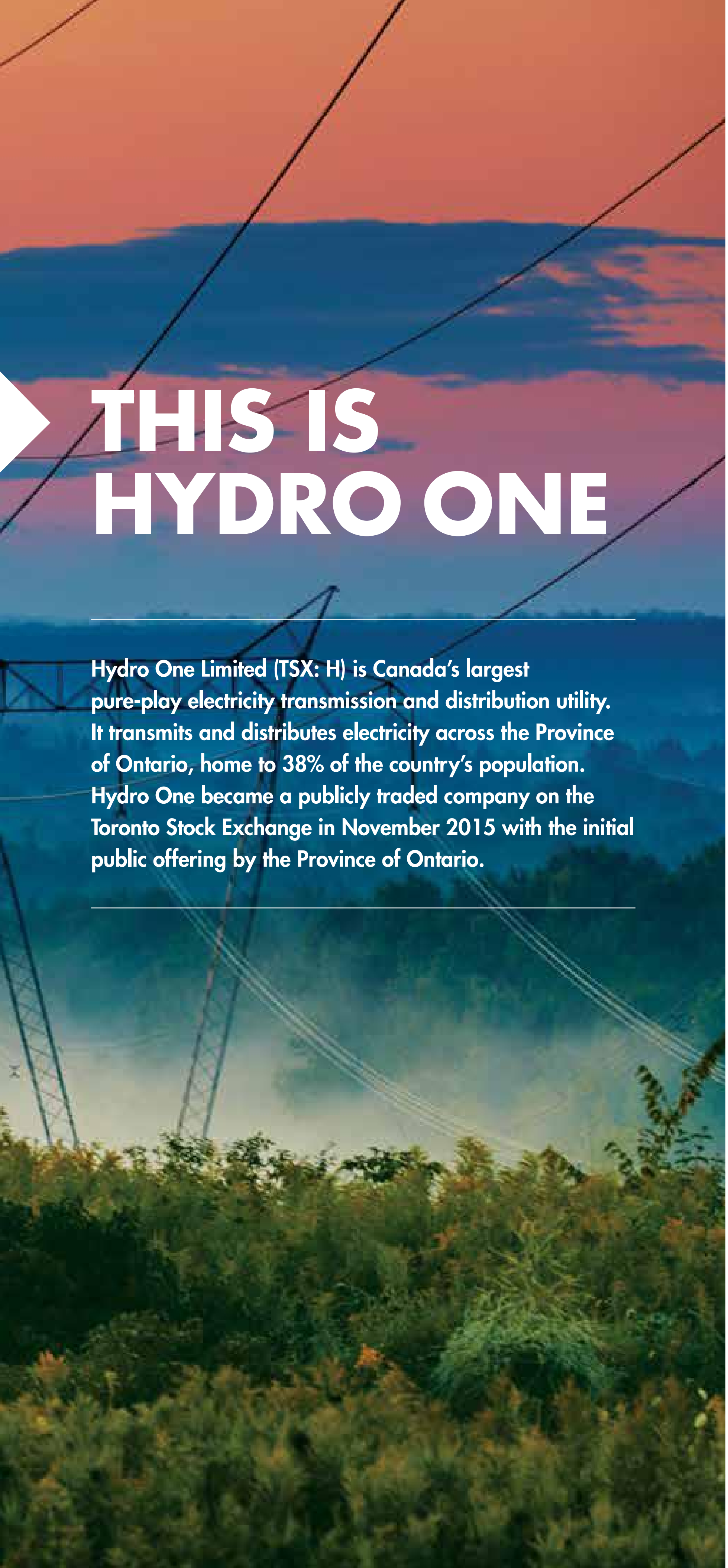
ANNUAL REPORT 2015

ONE OF NORTH AMERICA'S LARGEST
ELECTRICAL UTILITIES (TSX: H)

hydro One



THIS IS HYDRO ONE

Hydro One Limited (TSX: H) is Canada's largest pure-play electricity transmission and distribution utility. It transmits and distributes electricity across the Province of Ontario, home to 38% of the country's population. Hydro One became a publicly traded company on the Toronto Stock Exchange in November 2015 with the initial public offering by the Province of Ontario.

Hydro One Limited has three reportable segments: the electrical transmission business, the electrical distribution business and a third business segment consisting of the company's telecommunications business and certain corporate activities.

Together, the company's regulated transmission and distribution operations comprise approximately 88% of Hydro One's assets and provide 98% of its net revenues.

Hydro One Telecom leverages the company's telecommunications and tower assets to sell broadband fibre-optic capacity to other carriers, large corporations, government agencies, and healthcare and educational institutions.

A new governance agreement between Hydro One and the Province of Ontario was announced on April 16, 2015. On July 17, 2015 a new independent Board of Directors was appointed to govern Hydro One through its transition into a publicly traded company.

In November 2015, Hydro One Limited completed the initial public offering of 15% of its common shares, with the proceeds of the offering going to the Province of Ontario in the first phase of its previously announced sale of the majority of the company to the public. The common shares are listed and trade on the Toronto Stock Exchange under the symbol "H".

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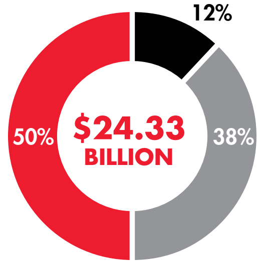
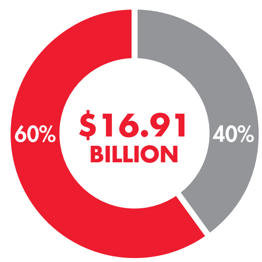
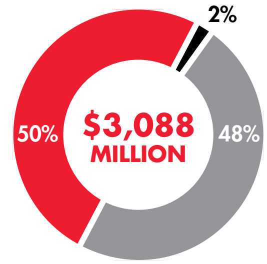
TOTAL ASSETS



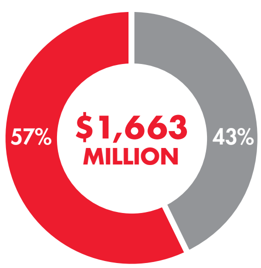
RATE BASE



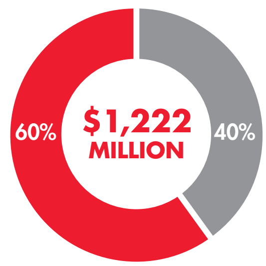
REVENUES (NET OF POWER COSTS)



CAPITAL INVESTMENTS



REGULATED EARNINGS BEFORE FINANCING CHARGES AND INCOME TAXES[1]



Transmission

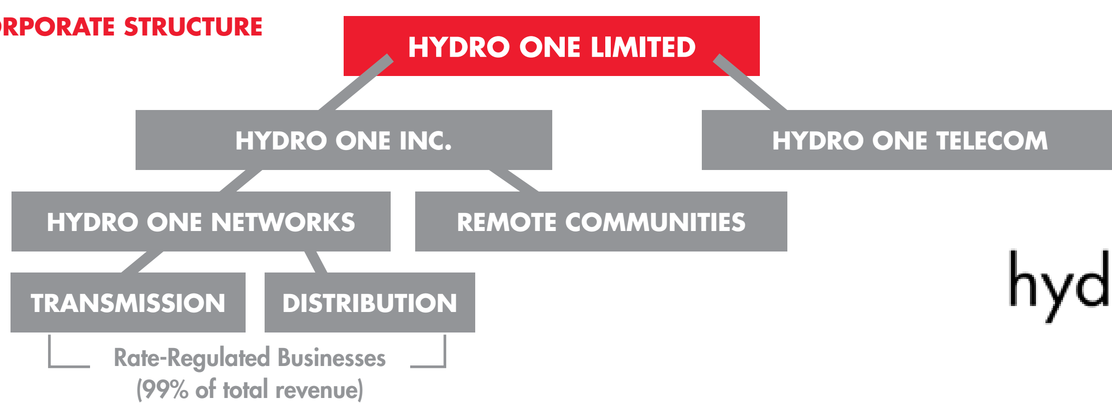
Distribution

Other

Year ended December 31 *(CAD millions, except as otherwise noted)*	**2015**	**2014**
Revenues	**6,538**	6,548
Purchased power	**3,450**	3,419
Revenues (net of purchased power)	**3,088**	3,129
Operation, maintenance and administration	**1,135**	1,192
Depreciation and amortization	**759**	722
Income before financing charges and income tax expense	**1,194**	1,215
Financing charges	**376**	379
Income tax expense	**105**	89
Net income attributable to common shareholders of Hydro One	**690**	**731**
Basic and diluted earnings per common share (EPS) *(Canadian dollars)*	**1.39**	1.53
Adjusted basic and diluted EPS *(Canadian dollars)*[2]	**1.16**	**1.23**
Net cash from (used in) operating activities	**(1,253)**	1,256
Adjusted net cash from operating activities[3]	**1,557**	1,256
Funds from (used in) operations (FFO)	**(1,479)**	1,293
Adjusted FFO[3]	**1,331**	1,293
Capital investments	**1,663**	1,530
Transmission – average monthly 60-minute peak demand *(MW)*	**20,344**	20,596
Distribution – average monthly units distributed to customers *(TWh)*	**28.9**	29.8

[1] Distribution and transmission segments
[2] Calculated using the number of common shares outstanding at December 31, 2015
[3] Excludes $2,810 million impact of deferred income tax asset that resulted as a consequence of leaving the payment in lieu of taxes regime and entering the federal tax regime.

CORPORATE STRUCTURE



hydro One

"Hydro One has a fully independent, diverse and deeply experienced Board of Directors to govern the Company's business, allowing it to execute as an independently controlled and professionally managed commercial entity well positioned to generate growth and value for our shareholders..."

DAVID F. DENISON

Chair of the Board

Dear fellow shareholders,

This was a seminal year of change and movement forward for Hydro One.

The transformative journey began last spring when the Province of Ontario, previously the sole shareholder of Hydro One, made a series of announcements relating to the company, including that it would broaden the ownership through an initial public offering. While the province remains the company's largest shareholder with 84% of the outstanding shares today, it has stated that it intends to make additional tranches of shares available to the public in stages, until it achieves its stated goal of reducing its ownership of Hydro One to 40%.

An integral part of the company's future is a renewed focus on customer service excellence and improved performance. During the past summer, the new Board announced the appointment of Mayo Schmidt as the company's new President and Chief Executive Officer and Michael Vels as its Chief Financial Officer. Both executives have strong track records and demonstrated experience in leading the transformation of large, publicly traded companies into high performance, innovative and customer-focused organizations that enhance customer service, accelerate growth and create significant shareholder value. Together with the technical expertise of the existing Hydro One team, I believe they can help to lead the company forward.

In addition to rolling up their sleeves in their critical new roles, the Hydro One management team led one of the largest and most successful initial public offerings in Canada in more than 15 years. The shares of Hydro One began trading on the Toronto Stock Exchange on November 5th.

To facilitate the change in ownership structure associated with the initial public offering, the province announced a new governance agreement between Hydro One and the province. This agreement ensures that the company is governed as an independent commercial entity going forward, providing confidence that the province is strictly playing the role of shareholder and not manager. Over the ensuing months, the new Board was assembled, drawing upon a diverse and accomplished group of proven leaders to govern Hydro One's transformation with a renewed focus on customer service excellence and improved performance and reliability. My fellow Board members were selected for their independence, commercial experience and strong governance expertise concerning public companies, customer service, the electricity sector and public policy.

As management and the Board work together to put in place a broad strategy to take Hydro One forward, work has already commenced across the company to strengthen customer service and performance excellence while putting in place initiatives to accelerate growth.

I would like to recognize the important foundational work of the previous Chair, Sandra Pupatello, and her Board, and acknowledge the efforts of former President and Chief Executive Officer Carmine Marcello: his contribution and leadership was essential to Hydro One's successful transition in 2015. Finally, I would like to thank the more than 5,500 Hydro One employees who work tirelessly – often around the clock and in hazardous weather and conditions – to ensure that electricity is delivered safely, reliably and cost-effectively to the millions of citizens of Ontario. It is their efforts and commitment that enable this great company to deliver for you – our shareholders, our customers and our communities – and we look forward to taking your company even further in 2016.

Thank you for your support,

David F. Denison, OC

Chair of the Board
Hydro One Limited

"2015 was a year of tremendous positive change for Hydro One. The team is intently focused on transforming this significant North American electrical utility into a high-performance commercial organization with considerable muscle to accelerate growth and consistently deliver on its promises…"

MAYO SCHMIDT

President and CEO

Dear fellow shareholders,

It is clear that 2015 was a pivotal year for your company as Hydro One charted a new course towards becoming a publicly traded, increasingly customer-focused and performance-driven company that offers dependable dividends and robust, predictable growth prospects.

It was a year of tremendous positive change that opened the door to a very bright future.

The size, strength and efficiency of our electrical grid is critical to reliably delivering the electricity that sustains and secures the economic and social well-being of every community in Ontario. This past year, the company made important investments to modernize and bolster the grid, investing approximately $1.7 billion in capital projects across both our transmission and distribution networks. Over the next few years, we will invest in significant infrastructure that is needed to maintain and modernize the critical electrical systems that we all depend on. We are stewards of this system, a mission we take very seriously.

Hydro One is embarking on a journey to take a leadership position in the North American utility landscape. Through building on our strong foundation, we have the opportunity to become a leader in this dynamic and evolving environment. To enable this, we have undertaken a strategic planning process to define our future.

We know that we need to understand the needs of our customers and stakeholders, including First Nations and Métis communities. Serving these needs effectively and efficiently will drive our business decisions. Our strategy will ensure we are ready to adapt to the emerging technology landscape and position our business for success. We will build world-class competencies and position ourselves to grow in the long term.

Hydro One is fortunate to operate in a stable and supportive regulatory environment with a transparent and predictable rate-setting process. The company plays an essential leadership role in the Ontario electricity industry.

We are focused on making life better for our customers. We improve their lives by treating them with respect, by making certain our system is reliable and ready for the future, by managing our costs and thus the cost of our service, and by having highly trained men and women across Ontario who are ready to respond 24/7 when storms and extreme weather disrupt service.

I believe we are uniquely positioned to make the most of the significant opportunities that lie ahead – and transform our business into a great Canadian company that stands out for its commitment to its customers and its performance for its shareholders.

On behalf of our 5,500 employees, thank you for your investment and interest in our progress. I would like to thank the Board of Directors for its support and its confidence in management. I would also like to thank employees across Ontario for embracing Hydro One's transformation and for their unwavering commitment to our customers. The future is bright.

Mayo Schmidt
President and CEO
Hydro One Limited

ELECTRICAL TRANSMISSION OPERATIONS

Hydro One's electrical transmission system totals approximately 29,000 circuit kilometres of high-voltage lines, towers and transformers, operating at 500 kV, 230 kV or 115 kV. Hydro One's grid transmits electricity from hydroelectric, nuclear, gas, wind and solar power generation sources to customers across Ontario, including 47 local distribution companies (LDCs), Hydro One's own local distribution systems and 90 large industrial customers directly connected to the transmission system.

The transmission operations service approximately 96% of the Province of Ontario by capacity and represent approximately 50% of the total assets and provide 50% of the net revenues of the company.

The transmission system is linked to five jurisdictions adjacent to Ontario (Manitoba, Minnesota, Michigan, New York and Quebec) through high-voltage interconnections. The transmission operations are regulated by the Ontario Energy Board (OEB) and the National Energy Board (NEB), together with an operating agreement with the Independent Electricity System Operator (IESO) and the North American Electric Reliability Corporation (NERC). Hydro One is also a partner in the Bruce to Milton Limited Partnership, which is a unique partnership between the company and the Saugeen Ojibway Nation Finance Corporation, operating a 176-kilometre long dual circuit transmission line between the Bruce Nuclear Generating Station and Hydro One's Milton Switching Station.

Our transmission assets can be divided into four functional categories:

1. **Transmission stations:** These facilities are used for the delivery of power, voltage transformation and switching, and serve as connection points for both customers and generators.
2. **Transmission lines:** Bulk transmission lines are main lines delivering power from generating stations or connections to receiving terminal stations. Area supply lines take power from the network and transmit it to customer supply transmission stations at customer load centres.
3. **Network operations:** All transmission assets and many sub-transmission assets are managed from one central location, the Ontario Grid Control Centre.
4. **Telecommunications facilities:** These facilities ensure the company's telecommunications requirements are met, with respect to the protection and operation of the power system as well as voice and administrative data. Our subsidiary Hydro One Telecom sells excess capacity on our fibre-optic network.

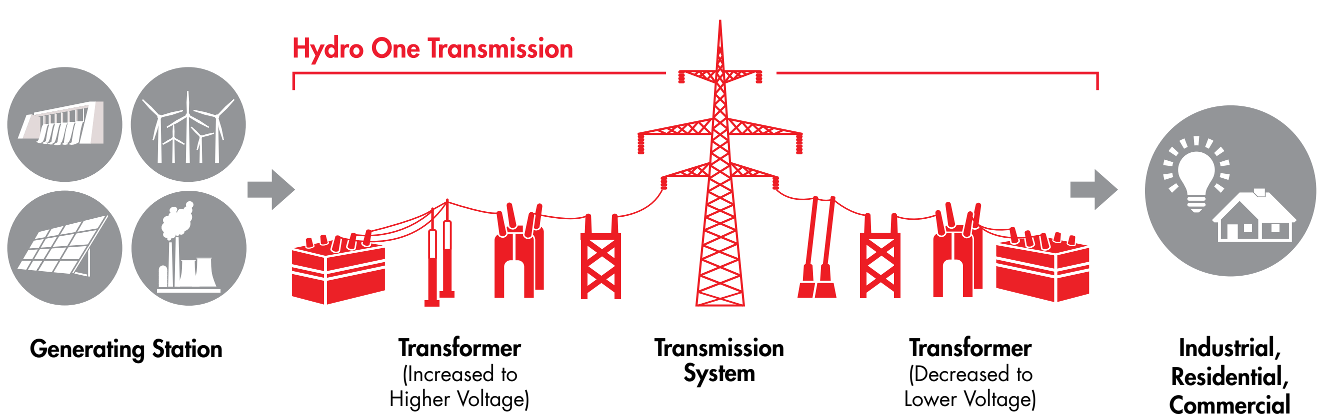
TRANSMISSION STATIONS
292

CIRCUIT KILOMETRES OF HIGH-VOLTAGE LINES
29,000

	TRANSMISSION SEGMENT
Customers	47 local distribution companies and 90 large industrial customers connected directly to the transmission network
Assets	292 transmission stations and approximately 29,000 circuit kilometres of high-voltage lines
Current Rate Base	$10.18 billion[1]
Allowed ROE (2016)	9.19%

[1] *Current transmission rate base as at December 31, 2015 includes 100% of B2MLP rate base.*

ONTARIO'S ELECTRICITY SYSTEM



ELECTRICAL DISTRIBUTION OPERATIONS

Hydro One's electrical distribution system totals approximately 123,000 circuit kilometres of lower-voltage power lines, poles and transformers, serving more than 1.3 million customers across Ontario.

As Hydro One operates in both rural and urban centres across Ontario, customers benefit from our integrated planning and the coordinated operations of our distribution and transmission systems and workforce.

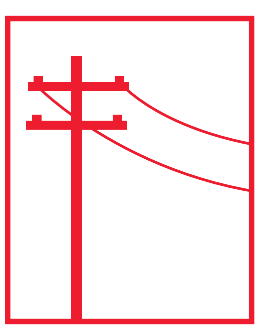
In June 2015, Hydro One announced the closing of its acquisition of Haldimand County Utilities, adding 21,200 customers to its local distribution network. In October, the closing of the acquisition of Woodstock Hydro Holdings Inc., including its wholly-owned subsidiary Woodstock Hydro Services Inc., added 15,800 customers, to be integrated with Hydro One's network in 2016.

Hydro One Remote Communities Inc. operates and maintains the generation and distribution assets used to supply electricity to 21 remote communities across northern Ontario that are not connected to the electricity transmission grid.

HYDRO ONE HAS A LARGELY RURAL AND SUBURBAN FOOTPRINT

1.3 MILLION CUSTOMERS

1.6 MILLION POLES

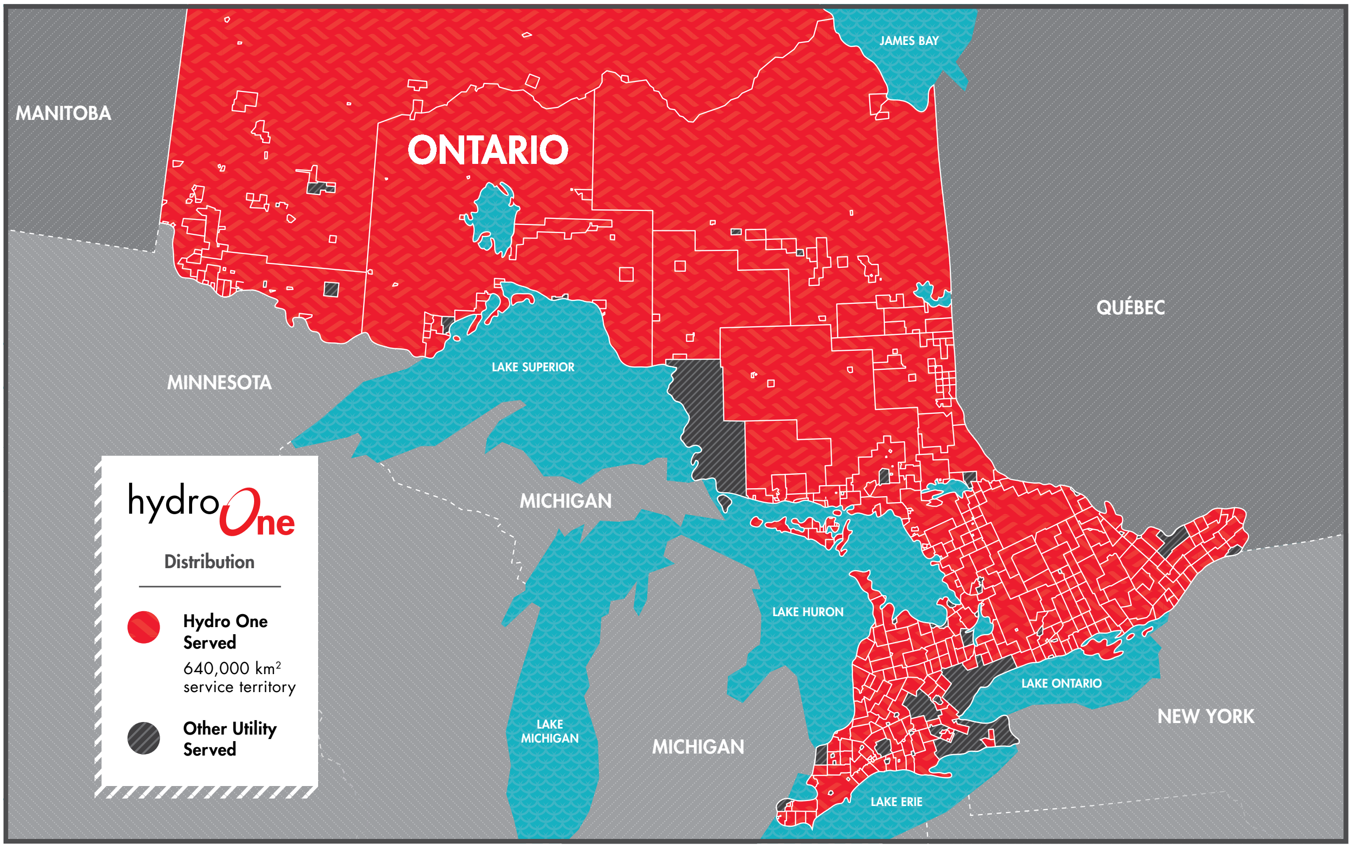


CIRCUIT KILOMETRES OF LOWER-VOLTAGE LINES

123,000

DISTRIBUTION AND REGULATION STATIONS

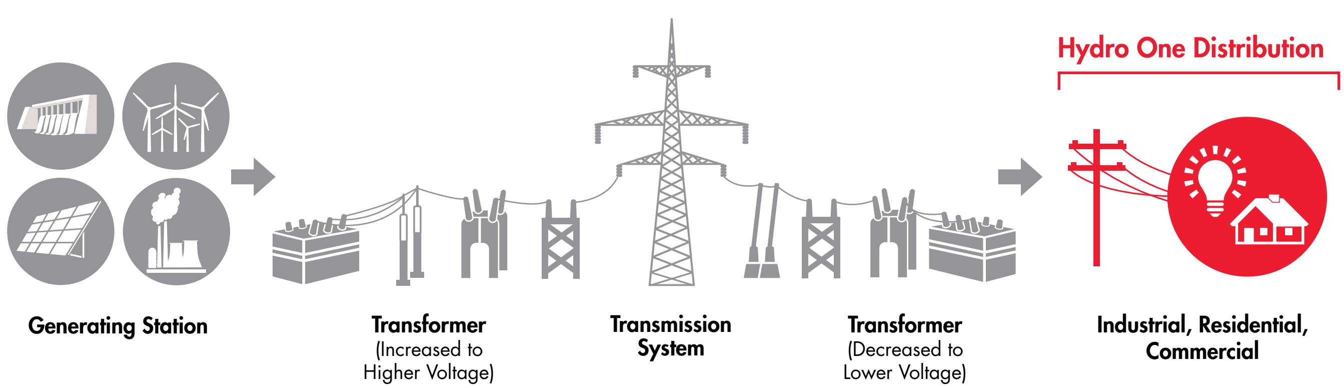
c. 1,000



	DISTRIBUTION SEGMENT
Customers	Approximately 1.3 million residential and business customers located mostly in rural areas, covering approximately 75% of the geographic area of the province, equal to roughly 640,000 square kilometres
Assets	123,000 circuit kilometres of lower-voltage distribution lines and approximately 1,000 distribution and regulating stations
Current Rate Base	$6.74 billion[1]
Allowed ROE (2016)	9.19%

[1] *Current distribution rate base as at December 31, 2015.*

ONTARIO'S ELECTRICITY SYSTEM



SERVING CUSTOMERS

Throughout 2015, Hydro One continued to put customers at the core of its decision-making, planning and execution. Every day the organization is focused on exceeding customer expectations. Whether it's launching new customer-friendly tools or mobilizing hundreds of employees to restore power, Hydro One's future path to success lies with our ability to exceed expectations.

CUSTOMER COMMITMENTS

In 2015, Hydro One was the first utility in Canada to launch Customer Commitments and service level guarantees. Developed with input from more than 40,000 customers and the company's Customer Service Advisory Panel, these five commitments provide assurance to customers about the service they can expect from Hydro One:

1. **We will provide you with a bill you can trust and understand.**
2. **We will provide you with a reliable supply of electricity.**
3. **We will make it easy to do business with us.**
4. **We will courteously and promptly work to resolve any issues you may have.**
5. **We will help you manage your electricity use.**

MOBILE OUTAGE APP

Customer service includes keeping customers connected to the information that is most important to them. The company's mobile outage app – available free to customers on their smartphones – was downloaded more than 60,000 times during 2015, totaling more than 286,000 since its launch in May 2012.

OUTAGE ALERTS

Drawing on the success of the mobile app, Hydro One was the first utility in Canada to launch personalized text and email alerts to customers, proactively informing them of outages that might affect their homes, cottages, farms or small businesses. Customers who register for this service receive alerts and updates on estimated times of restoration when an outage has been reported near their residences. Customers decide when and how they receive messages. To date, more than 7,000 customers have signed up for the service.

OFFICE OF THE OMBUDSMAN

To further support customer service, in October the company's Board of Directors appointed Fiona Crean to the role of Ombudsman for Hydro One. Having most recently served as the City of Toronto's ombudsman, Ms. Crean has worked in the area of complaints investigation and dispute resolution for more than 25 years.

STORM RESPONSE

Wind, snow and rain are a reality of life in Ontario. Across the province, the men and women of Hydro One are available 24 hours a day, seven days a week, to restore power for customers if the lights go out.

From the state-of-the-art Ontario Grid Control Centre, highly trained employees monitor all potential events, including weather, solar storms and geomagnetic disturbances that could affect Hydro One's system. The centre provides Hydro One with the industry-leading ability to remotely monitor and operate transmission equipment, respond to alarms and restore or reroute interrupted power.

When an alert is issued, the entire organization begins mobilizing staff and equipment to ensure power is restored as efficiently as possible. This means moving crews and equipment to where they are needed to make sure that power can be restored safely and quickly. With a workforce trained to the highest standards, crews can travel more than 500 kilometres to aid in restoration.

Working through holidays, in the harshest of conditions and in remote areas of the province, Hydro One employees not only restore power, but restore life back to normal for customers.

SAFETY, COMMUNITY AND THE ENVIRONMENT

SAFETY

The safety of the public, the communities Hydro One serves and the people of Ontario is every employee's responsibility.

From proper job planning to a trained and highly-skilled workforce, Hydro One emphasizes the importance of a safe workplace across every line of business. The result of this focus was seen in 2015 as Hydro One achieved its ambitious health and safety target, recording only 1.68 incidents per 200,000 hours worked.

Hydro One was awarded the Electrical Safety Authority's Powerline Safety Award for its community outreach with the company's mobile Electricity Discovery Centre. More than 30,000 visitors from 26 communities learned about electrical safety, how to conserve energy and the role Hydro One plays in the community.

COMMUNITY

Hydro One believes in the importance of connecting with the communities where we live and work through sponsorships, donations, scholarship programs and volunteering. These charitable giving programs broadly support safety and injury prevention, education and community support. They are an important link to the hundreds of communities that the company serves across the province.

Community Investment

Furthering the company's commitment to First Nations and Métis communities, in February 2015 Hydro One announced a three-year funding extension for Right to Play's Promoting Life-skills in Aboriginal Youth program. Hydro One is investing $100,000 each year to support after-school programming, sport for developmental activities, youth leadership, and health and wellness education.

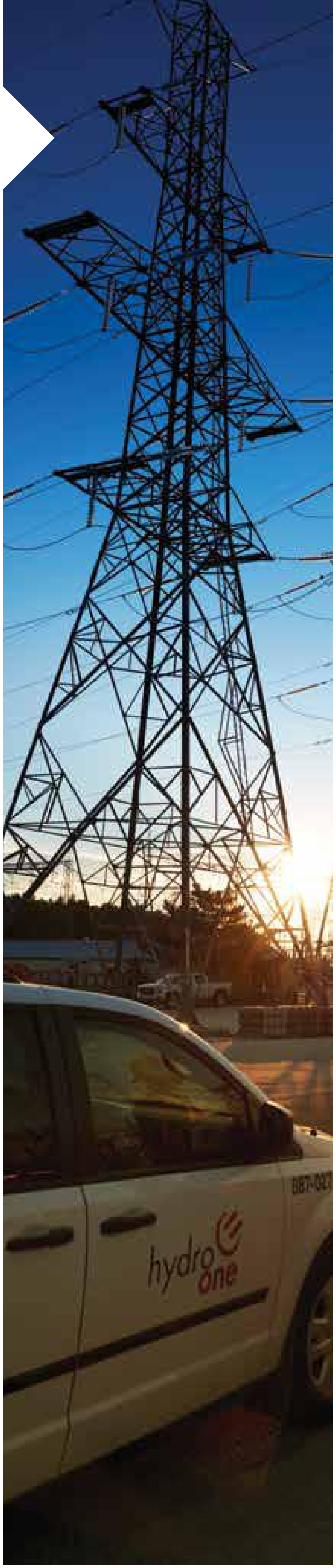
Scholarship Programs

In 2015, 13 female engineering students received Hydro One's Women in Engineering Scholarship for their outstanding achievements in electrical engineering. Winners receive a financial award along with a paid opportunity to work for Hydro One in a developmental student work placement. In celebration of National Aboriginal Day, in June Hydro One awarded 12 students with the Leonard S. (Tony) Mandamin Scholarship, which is granted annually to First Nations, Métis or Inuit post-secondary students.

CORPORATE SOCIAL RESPONSIBILITY

In January, Hydro One was designated as a Sustainable Electricity Company by the Canadian Electricity Association (CEA). This designation established by the CEA for utilities across Canada recognizes success building on the three foundational pillars of sustainability – environmental, social, and economic performance. It requires utilities to establish an Environmental Management System consistent with the ISO 14001 standard; to take the actions and meet the expectations laid out in the ISO 26000 Guidance on Social Responsibility. Hydro One is only the fourth electric utility in Canada to receive this designation.

***For further information on Hydro One's commitments to customers, safety, communities and the environment, please go to:* www.HydroOne.com/OurCommitment.**



CORPORATE GOVERNANCE OVERVIEW

Hydro One and the Board recognize the importance of corporate governance to the effective management of the company. Independence, integrity and accountability are the foundation of the company's approach to corporate governance. It is in the long-term best interests of our shareholders as well as our customers and promotes and strengthens relationships with employees, the communities in which the company operates and other stakeholders of the company.

Hydro One's Board of Directors was appointed on July 17, 2015, drawing upon a diverse and accomplished group of proven business leaders with deep corporate governance experience. The Board's primary role is overseeing corporate performance and the quality, depth and continuity of management required to meet the company's strategic objectives.

Hydro One is committed to best practices that will allow us to honour important fiduciary and oversight responsibilities. The Board regularly reviews and revises the company's governance practices in response to changing governance expectations and regulations. Our practices meet the rules and regulations issued by Canadian Securities Administrators and the Toronto Stock Exchange, including national corporate governance guidelines and related disclosure requirements.

The **Audit Committee** reviews the integrity of the company's financial statements and financial reporting process, internal control over financial reporting, enterprise risk management, disclosure controls and procedures, and compliance with other related legal and regulatory requirements. The committee also assists the Board in fulfilling its oversight responsibilities with respect to financial reporting, including overseeing the independence, qualifications and appointment of external auditors as well as the performance of the company's finance function, auditors (both external and internal) and the auditing, accounting and financial reporting process.

The **Nominating, Corporate Governance, Public Policy and Regulatory Committee** manages and oversees the process of nominating new directors to the Board in accordance with the governance agreement between the company and the Province of Ontario. The committee makes recommendations respecting the Board's approach to corporate governance, overseeing director orientation, education, performance evaluation, compensation and protection. The committee also oversees the company's relationship with shareholders, communities, stakeholders, electricity regulators, customers, the Province of Ontario and the company's approach to corporate social responsibility, including its sponsorship and donation programs.

The **Human Resources Committee** assists the Board in discharging the Board's oversight responsibilities relating to compensation, attraction and retention of key senior management, employee benefits, labour relations and succession planning.

The **Health, Safety, Environment and First Nations and Métis Committee** is responsible for oversight relating to effective occupational health and safety and environmental policies and practices at the company as well as the company's relationships with First Nations and Métis communities.

For a complete description of Hydro One's corporate governance structure and practices and individual director biographical information, please go to: www.HydroOne.com/Investors.

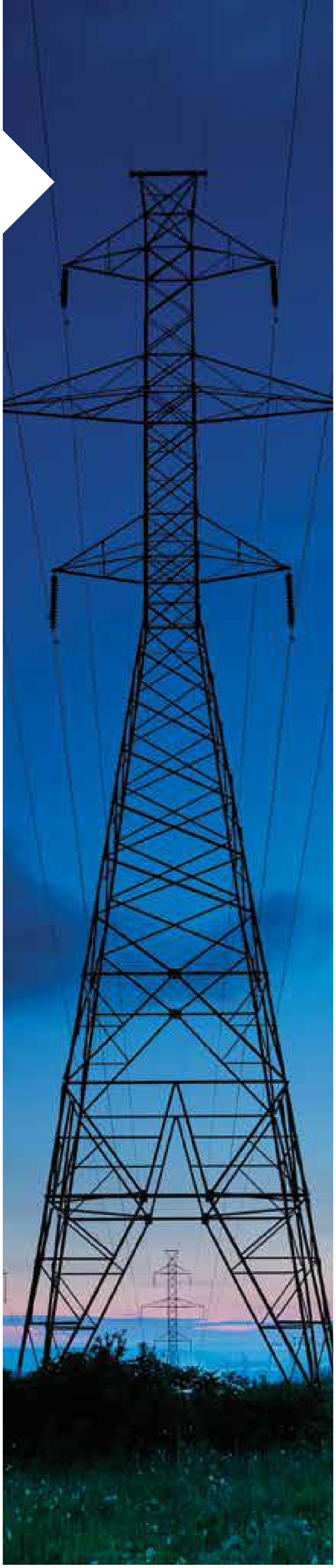
BOARD OF DIRECTORS AND COMMITTEES

★ = CHAIR
▲ = MEMBER

	AUDIT	NOMINATING, CORPORATE GOVERNANCE, PUBLIC POLICY AND REGULATORY	HUMAN RESOURCES	HEALTH, SAFETY, ENVIRONMENT AND FIRST NATIONS AND MÉTIS
David Denison (Chair)				
Mayo Schmidt (President and CEO)				
Ian Bourne		▲	★	
Charles Brindamour	▲		▲	
Marc Caira		▲	▲	
Christie Clark		▲	▲	
George Cooke	▲			▲
Marianne Harris			▲	★
Jim Hinds	▲			▲
Kathryn Jackson		▲		▲
Roberta Jamieson	▲			▲
Frances Lankin	▲	▲		
Philip Orsino	★	▲		
Jane Peverett		★	▲	
Gale Rubenstein			▲	▲

HYDRO ONE GOOD GOVERNANCE PRACTICES

100% Director Independence	Code of Business Conduct and Whistleblower Hotline	Annual Reviews of Board and Committee Performance
Board Education Sessions	Committee Authority to Retain Independent Advisors	Board and Committee In-Camera Discussions
Term Limits for Directors	Director Share Ownership Guidelines	Commitment to Director Diversity



WHY INVEST IN HYDRO ONE?

Opportunities to transition to a customer focused performance culture under Ontario's emerging incentive-based regulation

One of the largest electrical utilities in North America, with significant scale and a leadership position in Canada's most populated province

One of the strongest investment grade balance sheets in the utility sector

Unique combination of electrical transmission and local distribution, with no power generation assets or material exposure to commodity prices

Attractive dividend yield with 70 – 80% target payout ratio and opportunity for growth with rate base expansion

The business operates in a stable, transparent and collaborative rate-regulated environment

2015 IPO was the first phase of the largest-ever privatization by the Province of Ontario providing opportunities for public participation in asset transformation

Predictable growth profile, with consistent rate base growth expected under multi-year approved capital investment program to upgrade aging infrastructure

Strong governance structure and a fully independent Board allow the company to operate autonomously, transform its culture and drive shareholder value creation on multiple fronts

Proven management with demonstrated experience transforming organizations, accelerating performance and creating significant shareholder value

A unique opportunity to participate in the transformation of a premium, large-scale utility

hydroOne

Management's Discussion and Analysis

For the years ended December 31, 2015 and 2014

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes (the Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the year ended December 31, 2015. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. This MD&A provides information for the year ended December 31, 2015, based on information available to management as of February 11, 2016.

Initial Public Offering

In November 2015, Hydro One and the Province of Ontario (Province) completed an initial public offering (IPO) on the Toronto Stock Exchange of 15% of the Company's 595 million outstanding common shares. Prior to the completion of the IPO, Hydro One and its subsidiary, Hydro One Inc., completed a series of transactions (Pre-Closing Transactions) that resulted in, among other things, the acquisition by Hydro One of all of the issued and outstanding shares of Hydro One Inc. from the Province and the issuance of new common shares and preferred shares of Hydro One to the Province. Both Hydro One and Hydro One Inc. are reporting issuers. See section "Other Developments – Change in Hydro One Ownership Structure" for details relating to the IPO.

Current year information consists of the results of Hydro One Inc. up to October 31, 2015, and the consolidated results of Hydro One and Hydro One Inc. from November 1, 2015 to December 31, 2015. The comparative information consists of the results of Hydro One Inc. as at and for the year ended December 31, 2014.

Consolidated Financial Highlights And Statistics

Year ended December 31 *(millions of Canadian dollars, except as otherwise noted)*	2015	2014	Change
Revenues	6,538	6,548	(0.2%)
Purchased power	3,450	3,419	0.9%
Revenues, net of purchased power	3,088	3,129	(1.3%)
Operation, maintenance and administration costs	1,135	1,192	(4.8%)
Depreciation and amortization	759	722	5.1%
Financing charges	376	379	(0.8%)
Income tax expense	105	89	18.0%
Net income attributable to common shareholders of Hydro One	690	731	(5.6%)
Basic and diluted earnings per common share (EPS)	$1.39	$1.53	(9.2%)
Pro forma adjusted non-GAAP basic and diluted EPS[1]	$1.16	$1.23	(5.6%)
Net cash from (used in) operating activities	(1,253)	1,256	(199.8%)
Adjusted net cash from operating activities[1]	1,557	1,256	24.0%
Funds from (used in) operations (FFO)[1]	(1,479)	1,293	(214.4%)
Adjusted FFO[1]	1,331	1,293	2.9%
Capital investments	1,663	1,530	8.7%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	20,344	20,596	(1.2%)
Distribution: Units distributed to Hydro One customers *(TWh)*	28.9	29.8	(3.0%)
Debt to capitalization ratio[2]	50.7%	52.8%	

[1] See section "Non-GAAP Measures" for description and reconciliation of pro forma adjusted non-GAAP basic and diluted EPS, adjusted net cash from operating activities, FFO and adjusted FFO.

[2] Debt to capitalization ratio has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash) divided by total debt plus total shareholder's equity, including preferred shares but excluding any amounts related to non-controlling interest.

Overview

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and is the largest electricity distributor in Ontario. Hydro One has three business segments: (i) Transmission Business; (ii) Distribution Business; and (iii) Other Business (telecommunications).

Transmission Business

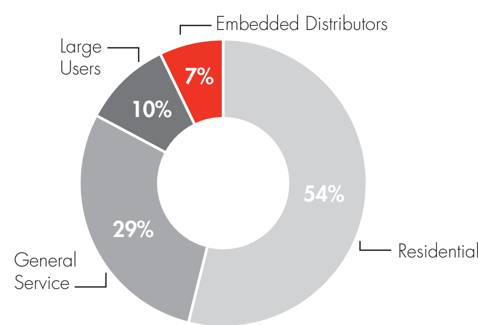
Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 96% of Ontario's transmission capacity. The Transmission Business consists of the transmission system operated by Hydro One Inc.'s subsidiary, Hydro One Networks Inc. (Hydro One Networks), and a 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The Company's Transmission Business is a rate-regulated business that earns revenues mainly from charging transmission rates that are approved by the Ontario Energy Board (OEB). The Transmission Business represented approximately 50% of the Company's total assets as at December 31, 2015, and approximately 50% of its total revenues, net of purchased power, in 2015.

	2015	2014
Electricity transmitted *(TWh)*	**137.0**	139.8
Transmission lines spanning the province *(circuit-kilometres)*	**29,355**	29,344
Rate base *(millions of Canadian dollars)*	**10,175**	9,934
Capital investments *(millions of Canadian dollars)*	**943**	845

Note: TWh means terawatt-hours.

Distribution Business

Hydro One's Distribution Business is the largest in Ontario and consists of the distribution system operated by Hydro One Inc.'s subsidiaries Hydro One Networks and Hydro One Remote Communities Inc. The Company's Distribution Business is a rate-regulated business that earns revenues mainly by charging distribution rates that must be approved by the OEB. The Distribution Business represented approximately 38% of the Company's total assets as at December 31, 2015, and approximately 48% of its total revenues, net of purchased power, in 2015.



	2015	2014
Electricity distributed to Hydro One customers *(TWh)*	**28.9**	29.8
Electricity distributed through Hydro One lines *(TWh)*[1]	**40.7**	42.4
Distribution lines spanning the province *(circuit-kilometres)*	**123,425**	123,657
Distribution customers *(number of customers)*	**1,347,231**	1,439,321
Rate base *(millions of Canadian dollars)*	**6,739**	6,415
Capital investments *(millions of Canadian dollars)*	**711**	680

1 Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the Independent Electricity System Operator (IESO).

Other Business

Hydro One's Other Business segment consists of the Company's telecommunications business and certain corporate activities. The telecommunications business provides telecommunications support for the Company's Transmission and Distribution Businesses, and also offers communications and IT solutions to organizations with broadband network requirements utilizing Hydro One Telecom Inc.'s (Hydro One Telecom) fibre optic network to provide diverse, secure and highly reliable connectivity. Hydro One's other business segment is not rate-regulated. This segment represented approximately 12% of Hydro One's total assets as at December 31, 2015, and approximately 2% of its total revenues, net of purchased power, in 2015.

Primary Factors Affecting Results Of Operations

Transmission Revenues

Transmission revenues primarily consist of the Company's transmission rates approved by the OEB which are charged based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to generate revenues necessary to construct, upgrade, extend and support a transmission system with sufficient capacity to accommodate maximum forecasted demand and a regulated return on the Company's investment. Peak electricity demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting electricity to markets outside of Ontario. Ancillary revenues include revenues from providing maintenance services to generators and from third-party land use.

Distribution Revenues

Distribution revenues include the distribution rates approved by the OEB and amounts to recover the cost of purchased power used by the customers of the distribution business. Distribution rates are designed to generate revenues necessary to construct and support local distribution system with sufficient capacity to accommodate existing and new customer demand and a regulated return on the Company's investment. Accordingly, distribution revenues are influenced by distribution rates, the cost of purchased power, and the amount of electricity the Company distributes. Distribution revenues also include ancillary distribution service revenues, such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous charges such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of purchased electricity delivered to customers within Hydro One's distribution service territory. These costs comprise the wholesale commodity cost of energy, in addition to wholesale market service and transmission charges levied by the Independent Electricity System Operator (IESO). Hydro One passes the cost of electricity that it delivers to its customers, and is therefore not exposed to wholesale electricity commodity price risk.

Operation, Maintenance and Administration Costs

Operation, maintenance and administration (OM&A) costs are incurred to support the operation and maintenance of the transmission and distribution systems, and other costs such as property taxes related to transmission and distribution lines, stations and buildings.

Transmission OM&A costs are incurred to sustain the Company's high-voltage transmission stations, lines and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and forestry control to maintain safe distance between line spans and trees. Distribution OM&A costs are required to maintain the Company's low-voltage distribution system, and include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, as well as land assessment and remediation. Hydro One manages its costs through ongoing efficiency and productivity initiatives, while continuing to complete planned work programs associated with the development and maintenance of its transmission and distribution networks.

Depreciation and Amortization

Depreciation and amortization costs relate primarily to depreciation of the Company's property, plant and equipment, and amortization of certain intangible assets and regulatory assets. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded on the balance sheet.

Financing Charges

Financing charges relate to the Company's financing activities, and include interest expense on the Company's long-term debt, gains and losses on interest rate swap agreements, net of interest earned on short-term and long-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment associated with the periods during which such assets are under construction before being placed in-service.

Income Taxes

Hydro One and its subsidiaries were exempt from regular Canadian federal and Ontario income tax (Federal Tax Regime) and instead paid an equivalent amount referred to as payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the *Electricity Act* (PILs Regime) until October 2015. Since then, Hydro One and its subsidiaries have been subject to the Federal Tax Regime. See further details in section "Other Developments – PILs Deemed Disposition Rules."

Results of Operations

Net Income

Net income attributable to common shareholders for the year ended December 31, 2015 of $690 million is a decrease of $41 million or 5.6% from the prior year. Significant influences on net income included:

- milder weather in 2015 resulted in a decrease in transmission revenues, mainly due to lower average Ontario peak demand in 2015 compared to 2014, particularly in June, November, and December;
- the effective income tax rate of 12.8% in 2015 compared to an effective tax rate of 10.6% in 2014;
- OM&A costs were lower than the prior year due to:
  - lower costs related to remediating the Company's customer information system, lower customer support expenses and lower bad debt expenses; and
  - lower preventative maintenance related to vegetation management; partially offset by
  - in 2014, insurance proceeds related to 2013 floods at the Company's Richview and Manby transformer stations were recorded as a reduction in 2014 OM&A costs and did not recur in 2015; and
  - during 2015, the Company recorded expenditures related to the integration of acquired local distribution companies.

Revenues

Year ended December 31 *(millions of Canadian dollars, except as otherwise noted)*	2015	2014	Change
Transmission	1,536	1,588	(3.3%)
Distribution	4,949	4,903	0.9%
Other	53	57	(7.0%)
	6,538	6,548	(0.2%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	20,344	20,596	(1.2%)
Distribution: Units distributed to Hydro One customers *(TWh)*	28.9	29.8	(3.0%)

Transmission Revenues

The decrease of $52 million or 3.3% in transmission revenues for the year ended December 31, 2015 was primarily due to lower average monthly Ontario 60-minute peak demand due to industrial customers shifting energy use away from system-wide peaks in the winter months of 2015 and generally milder weather in 2015, which more than offset increased transmission rates for 2015.

Distribution Revenues

The increase of $46 million or 0.9% in distribution revenues for the year ended December 31, 2015 was primarily due to higher OEB-approved distribution rates and higher purchased power costs, partially offset by decreased revenues due to the spin-off of Hydro One Inc.'s subsidiary, Hydro One Brampton Networks Inc. (Hydro One Brampton).

Operation, Maintenance and Administration Costs

Year ended December 31 *(millions of Canadian dollars)*	2015	2014	Change
Transmission	426	394	8.1%
Distribution	633	742	(14.7%)
Other	76	56	35.7%
	1,135	1,192	4.8%

Transmission OM&A Costs

The increase of $32 million or 8.1% in transmission OM&A costs for the year ended December 31, 2015 was primarily due to the following:

- expenses related to write-offs of project and inventory costs due to revisions of asset replacement strategies:
- higher expenditures during 2015 related to work required to adhere to the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (Cyber Security) standards; and

- in 2014, insurance proceeds related to 2013 floods at the Company's Richview and Manby transformer stations were recorded as a reduction in 2014 OM&A costs and did not recur in 2015; partially offset by:
- decreased expenditures related to forestry control and line clearing on the Company's transmission rights-of-way.

Distribution OM&A Costs

The decrease of $109 million or 14.7% in distribution OM&A costs for the year ended December 31, 2015 was primarily due to the following:

- a decrease in bad debt expense and lower expenditures related to remediation of the Company's customer information system;
- decreased vegetation management expenditures relating to the distribution line clearing and forestry control; and
- lower volume of work associated with locating and restoring power outages; partially offset by
- increased costs associated with responding to power outages as a result of multiple wind storms during the fourth quarter of 2015.

Other OM&A Costs

The increase of $20 million or 35.7% in other OM&A costs for the year ended December 31, 2015 was primarily due to costs to integrate acquired local distribution companies and increased compensation costs.

Depreciation and Amortization

The increase of $37 million or 5.1% in depreciation and amortization costs for the year ended December 31, 2015 compared to last year was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Income tax expense

Income tax expense for the year ended December 31, 2015 increased by $16 million compared to 2014, and the Company realized an effective tax rate of approximately 12.8% in 2015, compared to approximately 10.6% realized in 2014. The differences are primarily due to the following:

- lower capital cost allowance in excess of depreciation and amortization; and
- additional tax expense in connection with the spin-off of Hydro One Brampton; partially offset by
- an income tax recovery recorded on the revaluation to fair market value of the tax basis of the assets of Hydro One Inc. and its subsidiaries in excess of the Departure Tax triggered when Hydro One exited the PILs Regime.

Hydro One Brampton

On August 31, 2015, a dividend was paid to the Province by transferring to a company wholly-owned by the Province all of the issued and outstanding shares of Hydro One Brampton and inter-company indebtedness owed to Hydro One Inc. by Hydro One Brampton.

Hydro One's 2015 consolidated results of operations include the results of Hydro One Brampton up to August 31, 2015. The following tables present quarterly results of Hydro One Brampton that are included in consolidated results of Hydro One for the years ended December 31, 2015 and 2014.

Quarter ended *(millions of Canadian dollars)*	Mar. 31, 2015	Jun. 30, 2015	Sept. 30, 2015	Dec. 31, 2015	2015 Total
Revenues	125	129	100	–	354
Purchased power	107	111	88	–	306
OM&A	6	6	4	–	16
Depreciation and amortization	5	4	2	–	11
Income tax expense	–	1	(1)	–	–
Net income	7	7	7	–	21
Capital investments	9	11	8	–	28

Quarter ended *(millions of Canadian dollars)*	Mar. 31, 2014	Jun. 30, 2014	Sept. 30, 2014	Dec. 31, 2014	2014 Total
Revenues	127	115	128	125	495
Purchased power	109	99	109	109	426
OM&A	7	6	5	5	23
Depreciation and amortization	4	3	4	3	14
Income tax expense	–	1	–	2	3
Net income	7	6	10	6	29
Capital investments	2	10	6	9	27

Selected Annual Financial Statistics

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2015	2014	2013
Total revenue	6,538	6,548	6,074
Net income attributable to common shareholders	690	731	785
Basic and diluted EPS	$ 1.39	$ 1.53	$ 1.64
Dividends per common share declared	$ 1.83	$ 0.56	$ 0.42
Dividends per preferred share declared	$ 1.03	$ 1.38	$ 1.38
December 31 (millions of Canadian dollars)	2015	2014	2013
Total assets	24,328	22,550	21,625
Total non-current financial liabilities	8,224	8,373	8,301

Quarterly Results Of Operations

The following table sets forth unaudited quarterly information for 2015 and 2014. This information has been derived from the Company's unaudited interim Consolidated Financial Statements and audited annual Consolidated Financial Statements.

Quarter ended *(millions of Canadian dollars)*	Dec. 31, 2015	Sept. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sept. 30, 2014	Jun. 30, 2014	Mar. 31, 2014
Total revenues	1,522	1,645	1,563	1,808	1,662	1,556	1,566	1,764
Total revenues, net of purchased power	736	789	725	838	769	776	742	842
Net income attributable to common shareholders	143	188	131	228	216	169	110	236
Basic and diluted EPS	$ 0.26	$ 0.39	$0.27	$0.47	$ 0.45	$ 0.35	$ 0.23	$ 0.50

Non-GAAP Measures

FFO and Adjusted FFO

FFO is defined as net cash from operating activities, adjusted for the following: (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Adjusted FFO is defined as FFO, adjusted for the impact of the deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime. Management believes that FFO and adjusted FFO are helpful as supplemental measures of the Company's operating cash flows as they exclude timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders, and, in the case of adjusted FFO, the impact of the IPO-related deferred income tax asset. As such, these measures provide a consistent measure of the cash generating performance of the Company's assets.

The following table presents the reconciliation of net cash from operating activities to FFO and adjusted FFO:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Net cash from (used in) operating activities	(1,253)	1,256
Changes in non-cash balances related to operations	(208)	55
Preferred dividends	(13)	(18)
Distributions to noncontrolling interest	(5)	–
FFO	(1,479)	1,293
Less: Deferred income tax asset[1]	(2,810)	–
Adjusted FFO	1,331	1,293

[1] Impact of deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime

Pro forma Adjusted non-GAAP Basic and Diluted EPS

The following pro forma adjusted non-GAAP basic and diluted EPS has been prepared by management on a supplementary basis which assumes that the total number of common shares outstanding was 595,000,000 in each of the years ended December 31, 2015 and 2014. The supplementary pro forma disclosure is used internally by management subsequent to the IPO to assess the Company's performance and is considered useful because it eliminates the impact of the issuance of common shares to the Province prior to the IPO. Prior to the IPO, the Province was the sole shareholder of Hydro One and disclosure of EPS did not provide meaningful information. EPS is considered an important measure and management believes that presenting it for all periods based on the number of outstanding shares on, and subsequent to, the IPO provides users with a basis to evaluate the operations of the Company with comparable companies and with prior periods.

Year ended December 31	2015	2014
Net income attributable to common shareholders *(millions of Canadian dollars)*	690	731
Pro forma weighted average number of common shares		
Basic	595,000,000	595,000,000
Effect of dilutive share grant plans	94,691	–
Diluted	595,094,691	595,000,000
Pro forma adjusted non-GAAP EPS		
Basic	$1.16	$1.23
Diluted	$1.16	$1.23

Adjusted Net Cash from Operating Activities

Adjusted net cash from operating activities is defined as net cash from operating activities, adjusted for the impact of the deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime. Management believes that this measure is helpful as a supplemental measure of the Company's net cash from operating activities as it excludes the impact of the IPO-related deferred income tax asset. As such, adjusted net cash from operating activities provides a consistent measure of the Company's cash from operating activities compared to prior periods.

The following table presents the reconciliation of net cash from operating activities to adjusted net cash from operating activities:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Net cash from (used in) operating activities	(1,253)	1,256
Less: Deferred income tax asset[1]	(2,810)	–
Adjusted net cash from operating activities	1,557	1,256

[1] Impact of deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime

To the extent that adjusted net income is used in future continuous disclosure documents of Hydro One, it will be defined as net income, adjusted for certain items, including non-recurring items and other one-time items that management does not consider to be reflective of the operating performance of the Company. No such adjustments to net income are presented in this MD&A. Management believes that this measure will be helpful in assessing the Company's financial and operating performance in the future.

FFO, adjusted FFO, pro forma adjusted non-GAAP basic and diluted EPS, adjusted net cash from operating activities, and adjusted net income are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

Summary of Sources and Uses of Cash

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt borrowings and bank financing that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividends.

The following table presents the Company's sources and uses of cash during the years ended December 31, 2015 and 2014:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Operating activities		
Net income	713	747
Deferred income taxes	(2,844)	10
Changes in non-cash balances related to operations	208	(55)
Other	670	554
	(1,253)	1,256
Financing activities		
Long-term debt issued	350	628
Long-term debt retired	(585)	(776)
Short-term notes issued	1,491	–
Common shares issued	2,600	–
Dividends paid	(888)	(287)
Amount contributed by (distributed to) noncontrolling interest	(5)	72
Other	(9)	(32)
	2,954	(395)
Investing activities		
Capital expenditures	(1,632)	(1,504)
Capital contributions	62	–
Acquisitions of local distribution companies	(90)	(66)
Investment in Hydro One Brampton	(53)	–
Proceeds from investment	–	250
Other	6	(6)
	(1,707)	(1,326)
Net change in cash and cash equivalents	(6)	(465)

Cash from Operating Activities

Cash used in operations totalled $1,253 million for 2015 compared to cash from operations of $1,256 million in 2014. Cash from operations was affected by changes in deferred income tax assets that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime. Excluding this effect, cash from operations would have been $1,557 million for 2015, an increase of $301 million compared to prior year, mainly due to improved accounts receivable collections in 2015 and changes in regulatory accounts that impact revenue.

Cash from Financing Activities

Cash from financing activities of $2,954 million for 2015 compared to cash used in financing activities of $395 million in 2014. The increase in 2015 was primarily due to cash proceeds from common shares issued, and the issuance of short-term notes and long-term debt, partly offset by payment of dividends and repayment of long-term debt. See section "Liquidity and Financing Strategy" for details of the Company's liquidity and financing strategy.

In 2015, Hydro One issued $350 million of long-term debt under its Medium-Term Note (MTN) Program, compared to $628 million of long-term debt issued in 2014. In 2015, Hydro One repaid $550 million in maturing long-term debt, compared to no long-term debt maturing or repaid in 2014. In addition, long-term debt totalling $35 million assumed as part of the Haldimand County Utilities Inc. (Haldimand Hydro) acquisition and the Woodstock Hydro Holdings Inc. (Woodstock Hydro) acquisition was repaid in 2015.

In 2015, Hydro One paid dividends in the amount of $888 million ($875 million of common share dividends and $13 million of preferred share dividends), compared to dividends totalling $287 million paid in 2014. Included in dividends paid in 2015 was a special dividend paid to the Province prior to the completion of the IPO.

In November 2015, Hydro One issued 2.6 billion common shares to the Province for cash proceeds of $2.6 billion prior to the completion of the IPO.

Cash from Investing Activities

Cash used in investing activities was $1,707 million for 2015 compared to $1,326 million in 2014. The increase in 2015 was mainly due to higher capital investments in 2015 and the sale of an investment in 2014 for $250 million that did not recur in 2015. In 2015, cash totalling $90 million was used to purchase Haldimand Hydro and Woodstock Hydro, compared to cash of $66 million used to purchase Norfolk Power Inc. (Norfolk Power) in 2014. See section "Capital Investments" for details of the Company's capital investments, and section "Other Developments – Acquisitions" for details of the acquisitions of Haldimand Hydro and Woodstock Hydro.

Liquidity and Financing Strategy

Short-term liquidity is provided through funds from operations, Hydro One Inc.'s Commercial Paper Program, and the Company's consolidated credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of less than 365 days. At December 31, 2015, Hydro One Inc. had $1,491 million in commercial paper borrowings outstanding, compared to no commercial paper borrowings outstanding at December 31, 2014. In addition, the Company and Hydro One Inc. have revolving credit facilities totalling $2,550 million that mature between 2018 and 2020. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the Commercial Paper Program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2015, all of the Company's long-term debt totalling $8,723 million was issued by Hydro One Inc. under Hydro One Inc.'s MTN Program. At December 31, 2015, the maximum authorized principal amount of medium-term notes issuable under the MTN Program was $3.5 billion, with the entire amount remaining available until January 2018. The long-term debt consists of notes and debentures that mature between 2016 and 2064, and at December 31, 2015, had an average term to maturity of approximately 16.6 years and a weighted average coupon of 4.7%.

At December 31, 2015, Hydro One's corporate credit ratings from approved rating organizations were as follows:

Rating Agency	Corporate Credit Rating
Standard & Poor's Rating Services (S&P)[1]	A

[1] On September 18, 2015, S&P assigned its A corporate credit rating on Hydro One. The outlook is stable.

At December 31, 2015, Hydro One Inc.'s long-term and short-term debt ratings from approved rating organizations were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited (DBRS)[1]	R-1 (low)	A (high)
Moody's Investors Service (Moody's)[2]	Prime-2	A3
S&P[3]	A-1	A

1 On November 5, 2015, DBRS confirmed Hydro One Inc.'s issuer rating and senior unsecured debenture rating at A (high), downgraded its short-term debt rating to R-1(low) from R-1 (mid), and revised its trend to stable.

2 On November 5, 2015, Moody's downgraded the senior unsecured ratings of Hydro One Inc. to A3 from A2, downgraded its short term debt rating to Prime-2 from Prime-1, and revised its outlook on the Company to stable from negative.

3 On September 18, 2015, S&P affirmed its ratings on Hydro One Inc., including its A long-term corporate credit rating on the company.

At December 31, 2015, Hydro One and Hydro One Inc. were in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Effect of Interest Rates

The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates. See section "Risk Management and Risk Factors – Risks Relating to Hydro One's Business – Market, Financial Instrument and Credit Risk" for more details.

Pension Plan

In 2015, Hydro One contributed approximately $177 million to its pension plan, compared to contributions of approximately $174 million in 2014, and incurred $163 million in net periodic pension benefit costs, compared to $158 million incurred in 2014. The Company estimates that total pension contributions for 2016 will be approximately $180 million.

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase, and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates – Employee Future Benefits."

Capital Investments

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

In 2015, the Company made capital investments totalling $1,663 million and placed $1,476 million of new assets in-service, including replacements of end-of-life wood poles, new load connections, and the completion of two transformer replacements at the Hanmer Transmission Station, compared to $1,530 million of capital investments and $1,574 million of new assets placed in-service in 2014.

The following table presents Hydro One's 2015 and 2014 capital investments:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014	Change
Transmission			
Sustaining	706	625	13.0%
Development	166	132	25.8%
Other	71	88	(19.3%)
Total Transmission Capital Investments	943	845	11.6%
Distribution			
Sustaining	398	356	11.8%
Development	220	236	(6.8%)
Other	93	88	5.7%
Total Distribution Capital Investments	711	680	4.6%
Other Capital Investments	9	5	80.0%
Total Capital Investments	1,663	1,530	8.7%

Transmission Capital Investments

The increase of $98 million or 11.6% in transmission capital investments in 2015 was primarily due to the following:

- several system re-investments, including various end-of-life equipment replacements at certain transmission stations, including the Bruce, Richview, Larchwood and Wiltshire Transmission Stations, as well as the completion of two transformer replacements at the Hanmer Transmission Station;
- the continued work on some of the Company's major inter-area network and local area supply projects, such as the Clarington Transmission Station and Guelph Area Transmission Refurbishment projects;
- increased work on overhead lines refurbishment and replacement projects and programs;
- increased volume of work related to station security upgrades to prevent unauthorized entry to stations and enhance safety, and increased cyber system replacements, including firewall infrastructure, auxiliary equipment and management software, to adhere to the NERC Cyber Security standards; and
- increased volume of demand equipment replacements, as well as spare transformer equipment purchases to ensure readiness for unplanned transformer replacements; partially offset by
- decreased expenditures related to underground lines system replacements, as the end-of-life underground transmission cables between the Strachan Transformer Station and Riverside Junction were replaced and placed in-service in 2014.

Distribution Capital Investments

The increase of $31 million or 4.6% in distribution capital investments in 2015 was primarily due to the following:

- increased capital lines work, primarily related to multiple sustainment initiatives programs and higher volume of component replacements;
- increased work related to station refurbishment programs due to a larger volume of transformer purchases and more refurbishments accomplished during 2015; and
- increased storm restoration work as a result of multiple wind storms which occurred during the fourth quarter of 2015, as well as related power quality-related issues; partially offset by
- decreased expenses in 2015 due to completion of a smart meter installation project in 2014.

Major Transmission Projects

The following table summarizes the status of certain of Hydro One's major transmission projects at December 31, 2015:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date	Status
Toronto Midtown Transmission Reinforcement	Toronto Southwestern Ontario	New transmission line	2016	$123 million	$121 million	In progress
Guelph Area Transmission Refurbishment	Guelph area Southwestern Ontario	Transmission line upgrade	2016	$103 million	$67 million	In progress
Clarington Transmission Station	Oshawa area Eastern GTA	New transmission station	2018/2019	$297 million	$97 million	In progress
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	To be determined	–	OEB decision received in July 2015
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	As early as 2020	To be determined	–	Development work is in progress

Future Capital Investments

Hydro One anticipates that it will spend an average of over $1.6 billion per year over the next five years on total capital investments, with sustaining capital investments representing an average of approximately 60% of total capital investments in each year. The Company anticipates that these investments will contribute to improved reliability, customer service and operating efficiencies.

The following table summarizes Hydro One's annual projected capital investments for 2016 to 2020, by business segment:

(millions of Canadian dollars)	2016	2017	2018	2019	2020
Transmission	937	920	978	1,021	989
Distribution	706	692	690	729	663
Other	8	8	7	7	7
Total capital investments	1,651	1,620	1,675	1,757	1,659

The following table summarizes Hydro One's annual projected capital investments for 2016 to 2020, by category:

(millions of Canadian dollars)	2016	2017	2018	2019	2020
Sustaining	999	998	1,098	1,006	1,001
Development	416	435	360	479	480
Other	236	187	217	272	178
Total capital investments	1,651	1,620	1,675	1,757	1,659

Note: "Other" capital expenditures consist of special projects, such as those relating to information technology.

Other Obligations

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2015 *(millions of Canadian dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	8,723	500	1,350	878	5,995
Long-term debt – interest payments	7,368	397	741	654	5,576
Short-term notes payable	1,491	1,491	–	–	–
Pension contributions[1]	197	180	17	–	–
Environmental and asset retirement obligations[2]	248	22	51	58	117
Outsourcing agreements[3]	523	167	244	101	11
Operating lease commitments	45	11	19	12	3
Other	90	17	34	33	6
Total contractual obligations	18,685	2,785	2,456	1,736	11,708
Other commercial commitments *(by year of expiry)*					
Bank line[4]	2,550	–	800	1,750	–
Letters of credit[5]	154	154	–	–	–
Guarantees[5]	330	330	–	–	–
Total other commercial commitments	3,034	484	800	1,750	–

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2016 minimum pension contributions are based on an actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Pension contributions beyond 2016 are not estimable at this time.

[2] Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically-contaminated lands owned by the Company. Hydro One also records a liability for asset retirement obligations associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The forecasted expenditure pattern reflects the Company's planned work programs for the periods.

[3] Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., provides services to Hydro One, including settlements, source to pay services, pay operations services, information technology, finance and accounting services. The agreement with Inergi for these services expires in December 2019. In addition, Inergi provides customer service operations outsourcing services to Hydro One. The agreement for these services expires in February 2018. Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The current agreement with Brookfield expires in December 2024. The contractual amounts disclosed include an estimated contractual annual inflation adjustment in the range of 1.9% to 2.1%. Payments in respect of the Company's outsourcing agreements are recorded in OM&A costs on the Company's Consolidated Statements of Operations and Comprehensive Income or as a cost of capital programs.

[4] The Company and Hydro One Inc. have revolving credit facilities totalling $2,550 million that expire between 2018 and 2020.

[5] Hydro One Inc. currently has outstanding bank letters of credit of $139 million relating to retirement compensation arrangements. Hydro One Inc. provides prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. At December 31, 2015, Hydro One Inc. has provided a letter of credit to the IESO in the amount of $15 million to meet its current prudential requirements. Hydro One Inc. has also provided prudential support to the IESO on behalf of its subsidiaries as required by the IESO's Market Rules, using parental guarantees of $329 million, and on behalf of a distributor using total guarantees of $1 million.

Regulation

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its equity invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral accounts over specified timeframes.

The following table summarizes Hydro One's major regulatory proceedings:

Application	Year(s)	Type	Status
Electricity Rates			
Hydro One Networks	2015-2016	Transmission – Cost-of-service	OEB decision received
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
B2M LP	2015	Transmission – Interim	OEB decision received
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
Mergers Acquisitions Amalgamations and Divestitures			
Haldimand Hydro	n/a	Acquisition	OEB decision received
Woodstock Hydro	n/a	Acquisition	OEB decision received
Leave to Construct			
Supply to Essex County Transmission Reinforcement Project	n/a	Section 92	OEB decision received

Hydro One has secured rate orders for Hydro One Networks' transmission business through 2016, for B2M LP through 2019, and for Hydro One Networks' distribution business to the end of 2017.

The following table summarizes the status of Hydro One's electricity rate applications.

Application	Date of Rate Application Approval	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Date of Rate Order Filing	Rate Order Status
Transmission:						
Hydro One Networks	January 2015	2015	9.30% (A)	$9,651 million	January 2015	Approved
		2016	9.19% (A)	$10,040 million	November 2015	Approved
B2M LP	December 2015	2015	9.30% (A)	$523 million	December 2014	Approved
		2016	9.19% (A)	$516 million	January 2016	Approved
		2017	9.71% (F)	$509 million	–	To be filed 2016 Q4
		2018	9.96% (F)	$502 million	–	To be filed 2017 Q4
		2019	10.01% (F)	$496 million	–	To be filed 2018 Q4
Distribution:						
Hydro One Networks	March 2015	2015	9.30% (A)	$6,552 million	April 2015	Approved
		2016	9.19% (A)	$6,863 million	January 2016	Approved
		2017	9.71% (F)	$7,190 million	–	To be filed 2016 Q4

Hydro One Networks

Hydro One Networks' transmission 2016 revenue requirement of $1,480 million is reflected in the Uniform Transmission Rates (UTR) Decision and Order. Hydro One Networks plans to submit a transmission application for 2017-2018 rates in the second quarter of 2016.

The Hydro One Distribution forecast for 2017 will be subject to adjustments for cost of capital parameters. Hydro One Networks plans to submit a distribution application for 2018-2022 rates in the first quarter of 2017.

B2M LP

On December 29, 2015, the OEB issued a Decision and Order approving the five-year revenue requirement for years 2015-2019 inclusive, approving the recovery of $8 million start-up costs in rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes. The January 14, 2016, Decision and Rate Order approved the B2M LP revenue requirement recovery through the 2016 UTRs.

Supply to Essex County Transmission Reinforcement Project

On July 16, 2015, the OEB issued a Decision and Order granting Hydro One Networks Leave to Construct a new 13-kilometre 230 kV double-circuit transmission line in the Windsor-Essex region. The Decision and Order includes standard conditions of adherence to the system impact assessment and the connection impact assessment, and requires construction to commence within twelve months. In addition, on August 28, 2015, the OEB issued a letter stating that given the complexities and implications of the issues relating to cost allocation, including potential changes to the provisions in the Distribution System Code and the Transmission System Code, the OEB will not proceed with cost allocation through an adjudicative process, but will review these issues from a policy perspective.

On January 7, 2016, the OEB initiated its policy review. In the southeast Essex County, a number of large distribution-connected customers are a factor driving the need for new transmission capacity, such as the new Leamington transmission station. Three other distributors embedded in Hydro One's distribution area will also benefit from this investment. Therefore, Hydro One has proposed that its share of this transmission investment be shared proportionately between Hydro One and the other identified beneficiaries in the area. The OEB consultation will review the concept of proportional benefit and its application, as the policy and regulatory framework to flow transmission costs through to identified distribution-connected customers is not in place.

Other Regulatory Developments

Time-of-Use (TOU) Pricing Decision and Order

On March 26, 2015, the OEB issued a Decision and Order to amend Hydro One Networks' distribution license to include an exemption from the requirement to apply TOU pricing to approximately 170,000 Regulated Price Plan customers that are outside the smart meter telecommunications infrastructure. The exemption expires December 31, 2019.

Distribution System Code Requirements

In April 2015, the OEB introduced a Notice of Amendment to the Distribution System Code requiring electricity distributors to issue monthly bills to non-seasonal residential and certain general service customers by the end of 2016. In addition, the OEB amended the Distribution System Code imposing a 98% billing accuracy requirement, and provisions allowing a local distribution company to issue a bill based on estimated consumption only twice every twelve months to these customers. In September 2015, the OEB issued its Decision and Order amending Hydro One Networks' electricity distribution licence to include an exemption from the requirement for estimated billing and billing accuracy for the 170,000 hard-to-reach customers that are currently exempt from TOU billing, for a term ending on December 31, 2019.

On December 31, 2015, Hydro One submitted a report to the OEB summarizing that as of November 2015, approximately only 101,000 "hard-to-reach" customers received estimated bills in 2015 and significant improvements were realized in estimated billing accuracy due to the availability of better customer-specific historical usage data on which the estimation algorithms are based.

Conservation and Demand Management

In accordance with a directive from the Minister of Energy and Infrastructure dated March 31, 2010, as a condition of licence, certain licensed electricity distributors must meet the IESO established targets for the reduction of electricity consumption and peak provincial electricity demand. On September 30, 2015, Hydro One Networks filed its annual Conservation and Demand Management (CDM) Report with the OEB. In 2014, Hydro One Networks achieved 167.4 MW in peak demand savings and 898.4 GWh in energy savings, which represent 78.4% and 79.5% of its peak demand and energy reduction targets, respectively. Although Hydro One Networks did not meet its peak demand reduction target, no punitive action will be taken against the Company.

Rate Design (previously Revenue Decoupling for Distributors)

In April 2015, the OEB issued a report, *"Board Policy: A New Distribution Rate Design for Residential Electricity Customers"*, outlining its new policy on fully fixed distribution charges for residential customers. The current distribution charges are a combination of fixed and variable rates. Under the new policy, electricity distributors will structure their residential rates such that all distribution service costs will be collected through a fixed monthly charge only. The new policy will be implemented gradually over a four year period, with increases in the fixed rate and decreases in the variable rate, resulting in a fixed rate only by 2019. The new rate design will enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services. It will also provide greater revenue stability for distributors, including Hydro One.

In its December 22, 2015 Decision, the OEB has increased the transition period for Hydro One Networks' certain customer classes to eight years to mitigate excessive bill impacts.

In January 2016, the OEB issued a Decision and Rate Order for the area formerly served by Norfolk Power approving Hydro One's implementation plan to transition residential customers to fixed rates over a four year period. Although Norfolk Power customers' rates are frozen for five years, the OEB Order approved Tariffs of Rates and Charges for 2016 only.

In 2015, Hydro One Networks filed applications with the OEB with respect to the new rate design for residential customers in the service areas formerly served by Haldimand Hydro and Woodstock Hydro that include fixed rates for five years and implementation plans to transition to fixed distribution rates. Approvals for these applications are pending.

Performance Measurement for Electricity Distributors

On September 18, 2015, Hydro One Networks submitted its 2014 Performance Scorecard to the OEB. In addition to ongoing operations, a major focus in 2014 was investing in improvements to the Company's customer call centre and billing operations. Hydro One plans to continue developing targeted products and services that respond to its customers' unique needs, including realizing value from the new customer information system, simplifying and shortening timeframes for the delivery of services, and enhancing accessibility to allow effective self-service for simple transactions. The Company is also committed to delivering programs to help its customers manage their energy consumption. Hydro One Networks' 2014 Scorecard was posted on the Hydro One and the OEB websites.

Renewed Regulatory Framework for Transmitters

In 2015, the OEB initiated a discussion to develop a framework for the application of Renewed Regulatory Framework principles to transmitters, and in January 2016, issued a new set of draft filing requirements for transmitters for discussion.

Transmitter Consolidations

On January 19, 2016, the OEB issued the *Handbook for Electricity Distributor and Transmitter Consolidations* (the "handbook") to provide guidance on applications for approval of electricity utility consolidations by way of mergers, acquisitions, amalgamations and divestitures and subsequent rate applications. The handbook is intended to provide guidance on the process for review of consolidation applications by the OEB and affirms the OEB's policy of using the "no harm" test in reviewing consolidation applications. This test requires applicants to demonstrate that the costs to serve acquired customers post-consolidation will be no higher than they otherwise would be without consolidation. In addition the OEB will consider whether any price premium paid on the acquisition is financially burdensome to the applicant, as any premium paid over historic asset value is not recoverable in rates. The handbook will allow applicants to defer rebasing of the acquired utility for up to a 10 year period with the view of permitting the applicant to fully realize the anticipated efficiency gains and offset the overall costs of the transaction.

Other Developments

Change in Hydro One Ownership Structure

During the fourth quarter of 2015, Hydro One and Hydro One Inc. completed a series of Pre-Closing Transactions that resulted in, among other things, the acquisition by Hydro One of all of the issued and outstanding shares of Hydro One Inc. and the issuance of new common shares and preferred shares of Hydro One to the Province. On November 5, 2015, Hydro One and the Province concluded the IPO of Hydro One on the Toronto Stock Exchange, whereby 81.1 million of the 595 million outstanding common shares of Hydro One were sold to the public. On November 12, 2015, the underwriters of the IPO exercised their option to purchase an additional 8.15 million common shares of Hydro One from the Province. All proceeds from the IPO were received by the Province. All of the regulated business and outstanding notes and debentures of Hydro One at the time of the IPO remain at Hydro One Inc. The final prospectus associated with the IPO, which contains details of the IPO, recapitalization and corporate structure, is posted on www.sedar.com.

PILs Deemed Disposition Rules

In connection with the IPO, upon ceasing to be exempt from tax under the Federal Tax Regime in October 2015, Hydro One and its subsidiaries were deemed to dispose of their assets for proceeds equal to their fair market value, triggering a PILs liability of $2.6 billion (Departure Tax). The Departure Tax amount was confirmed in writing by the Minister of Finance and was paid to the OEFC in 2015. To enable Hydro One and its subsidiaries to pay the Departure Tax, the Province made an equity injection of $2.6 billion in Hydro One and received 2.6 billion common shares of Hydro One. The revaluation of the tax basis of the assets of Hydro One Inc. and its subsidiaries to fair market value resulted in a net deferred tax recovery of $2,619 million recorded in 2015.

Class Action Lawsuit

In September 2015, Hydro One and three of its subsidiaries were served with a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. Hydro One intends to defend the action. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

Acquisitions

Integration of Norfolk Power

The Company acquired Norfolk Power in August 2014. The purchase price for Norfolk Power, adjusted for working capital and other closing adjustments, was approximately $68 million. Due to this acquisition, approximately 18,000 new customers were added to Hydro One's Distribution Business. In September 2015, the Company completed the integration of Norfolk Power, including the integration of employees, customers, business processes, information and operations. This successful integration will allow the Company to standardize processes and leverage key lessons learned to drive efficiency and improvements when integrating other acquisitions in the future.

Acquisition of Haldimand Hydro

In June 2015, Hydro One completed the acquisition of Haldimand Hydro, an electricity distribution company located in southwestern Ontario, following approval of the acquisition by the OEB in March 2015. The purchase price for Haldimand Hydro, adjusted for working capital and other closing adjustments of approximately $8 million, was approximately $73 million. The goodwill of approximately $33 million arising from the Haldimand Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Haldimand Hydro. Due to this acquisition, approximately 21,000 new customers were added to Hydro One's Distribution Business. Integration of Haldimand Hydro is ongoing.

Acquisition of Woodstock Hydro

In October 2015, Hydro One completed the acquisition of Woodstock Hydro, an electricity distribution company located in southwestern Ontario, following approval of the acquisition by the OEB in September 2015. The purchase price for Woodstock Hydro, adjusted for preliminary working capital and other closing adjustments, was approximately $32 million. The preliminary goodwill of approximately $17 million arising from the Woodstock Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Woodstock Hydro. Due to this acquisition, approximately 16,000 new customers were added to Hydro One's Distribution Business. Integration of Woodstock Hydro is ongoing.

Great Lakes Power Transmission Purchase Agreement

On January 28, 2016, Hydro One reached an agreement to acquire from Brookfield Infrastructure various entities that own and control Great Lakes Power Transmission LP, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario, for $222 million in cash, subject to customary adjustments, plus the assumption of approximately $151 million in outstanding indebtedness. The acquisition is pending a *Competition Act* approval as well as regulatory approval from the OEB.

Hydro One Workforce

Hydro One has a skilled and flexible work force of over 5,500 regular employees and over 2,000 non-regular employees province-wide, comprising a mix of skilled trades, lines staff, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to access highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2015.

	Regular Employees	Non-Regular Employees	Total
Power Workers' Union (PWU)	3,419	636[1]	4,055
The Society of Energy Professionals (Society)	1,394	57	1,451
Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2]	–	1,346	1,346
International Brotherhood of Electrical Workers (IBEW)	63	4	67
Total employees represented by unions	4,876	2,043	6,919
Management and non-represented employees	640	34	674
Total employees	5,516	2,077	7,593

[1] Includes 475 non-regular "hiring hall" employees covered by PWU agreement.

[2] Employees are jointly represented by both unions. The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

Collective Agreements

The PWU represents the majority of the skilled trade personnel employed by Hydro One. In April 2015, Hydro One reached an agreement with the PWU for a renewal of the collective agreement. The agreement is for a three-year term, covering April 1, 2015 to March 31, 2018. The agreement was ratified by the PWU and the Hydro One Board of Directors in July 2015.

The Society represents professional and certain first-level supervisory staff employed by Hydro One. In July 2015, Hydro One reached an agreement with the Society for an early renewal of the collective agreement. The agreement is for a three-year term, covering April 1, 2016 to March 31, 2019. The agreement was ratified by the Society and the Hydro One Board of Directors in August 2015.

In July 2015, Hydro One reached an agreement with the CUSW for a renewal of the collective agreement. The agreement is for a three-year term, covering May 1, 2014 to April 30, 2017. The agreement was ratified by CUSW in September 2015 and the Hydro One Board of Directors in August 2015.

The EPSCA is an employers' association of which Hydro One is a member. A number of the EPSCA construction collective agreements, which bind Hydro One, expired in April 2015. Ratified five-year renewal collective agreements, covering May 1, 2015 to April 30, 2020, have been reached with The United Association of Plumbers and Pipefitters, The Ironworkers, The Rodmen, The Boilermakers, The Insulators, The Sheet Metal Workers, The Roofers, the Labourers International Union of North America (LIUNA), the Operating Engineers (OE) and the Teamsters.

Share-based Compensation

Share Grant Plans

At December 31, 2015, Hydro One had two share grant plans, one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. The number of common shares granted annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. The number of common shares granted annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares.

Directors' Deferred Share Unit (DSU) Plan

Under the Company's Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company will match 50% of the employee's contributions, up to maximum Company contribution of $25,000 per calendar year. No contributions were made under the ESOP during 2015.

Long-term Incentive Plan

The Board of Directors of Hydro One adopted a Long-term Incentive Plan effective August 31, 2015. Under the Long-term Incentive Plan, long-term incentives will be granted to certain executive and management employees, and all equity-based awards will be settled in newly-issued shares of Hydro One from treasury, consistent with the provisions of the plan.

The mix of long-term incentive vehicles has not yet been determined and, accordingly, the Long-term Incentive Plan provides flexibility to award a range of vehicles, including restricted share units, performance share units, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance. It is expected that the specific incentive vehicles and performance targets associated with the Long-term Incentive Plan will be decided in early 2016, after which the incentive grants will commence. No long-term incentive payments were awarded during 2015.

Related Party Transactions

The Province is the majority shareholder of Hydro One. The OEFC, IESO, Ontario Power Generation Inc. (OPG), the OEB, and Hydro One Brampton are related parties to Hydro One because they are controlled or significantly influenced by the Province. The following is a summary of the Company's related party transactions during the year ended December 31, 2015:

The Province

- During 2015, Hydro One paid dividends to the Province totalling $888 million (2014 – $287 million). In addition, on August 31, 2015, Hydro One declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton.
- On November 4, 2015, Hydro One issued 2.6 billion common shares to the Province for proceeds of $2.6 billion.
- In 2015, Hydro One Inc. incurred certain IPO related expenses totaling $7 million which will be reimbursed to the Company by the Province and reimbursed by the Company to Hydro One Inc.

IESO

- During 2015, Hydro One purchased power in the amount of $2,318 million from the IESO-administered electricity market, compared to $2,601 million purchased in 2014.
- Hydro One receives revenues for transmission services from the IESO, based on OEB-approved Uniform Transmission Rates. The Company's 2015 transmission revenues include $1,548 million related to these services, compared to $1,556 million in 2014.
- Hydro One receives amounts for rural rate protection from the IESO. The Company's 2015 distribution revenues include $127 million related to this program, compared to $127 million in 2014.
- Hydro One receives revenues related to the supply of electricity to remote northern communities from the IESO. The Company's 2015 distribution revenues include $32 million related to these services, compared to $32 million in 2014.
- The IESO (Ontario Power Authority prior to January 1, 2015) funds substantially all of Hydro One's CDM programs. The funding includes program costs, incentives, and management fees. During 2015, the Company received $70 million related to these programs, compared to $33 million received in 2014.

OPG

- During 2015, Hydro One purchased power in the amount of $11 million from the OPG, compared to $23 million purchased in 2014.
- Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. The Company's other 2015 revenues include $7 million related to these service level agreements, compared to $12 million in 2014. OM&A costs related to the purchase of services with respect to these service level contracts were not significant in 2015 and 2014.

OEFC

- During 2015, Hydro One made PILs to the OEFC totalling $2.9 billion, including Departure Tax of $2.6 billion, compared to payments of $86 million made in 2014.
- During 2015, Hydro One purchased power in the amount of $6 million from power contracts administered by the OEFC, compared to $9 million purchased in 2014.
- In 2015, the Company paid $8 million to the OEFC, compared to $5 million paid in 2014, 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. Hydro One has not made any claims under the indemnity since it was put in place in 1999. Hydro One and the OEFC, with the consent of the Minister of Finance, have agreed to terminate the indemnity effective October 31, 2015.

OEB

- Under the *OEB Act*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. During 2015, Hydro One incurred $12 million in OEB fees, compared to $12 million incurred in 2014.

Hydro One Brampton

- Effective August 31, 2015, Hydro One Brampton is no longer a subsidiary of Hydro One Inc., but is indirectly owned by the Province. Subsequent to August 31, 2015, Hydro One continues to provide certain management, administrative and smart meter network services to Hydro One Brampton pursuant to certain service level agreements, which are provided at market rates. During 2015, revenues related to the provision of services with respect to these service level agreements were $1 million.

At December 31, 2015, the amounts due from and due to related parties as a result of the transactions described above were $191 million and $138 million, compared to $224 million and $227 million at December 31, 2014, respectively. At December 31, 2015, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $134 million, compared to $214 million at December 31, 2014.

Risk Management and Risk Factors

Risks Relating to Hydro One's Business

Regulatory Risks and Risks Relating to Hydro One's Revenues

Risks Relating to Obtaining Rate Orders

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will permit Hydro One to recover all costs actually incurred, including operations, maintenance and administration costs, costs accumulated in other regulatory accounts (including, for instance, deferral and variance accounts), costs of debt and income taxes, or to earn a particular return on equity. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, may materially adversely affect: Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed return on equity depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance and administration costs above those included in the Company's approved revenue requirement, higher capital expenditures than those approved in rate decisions, or additional financing charges because of increased debt amounts or higher interest rates. The inability to obtain acceptable rate decisions or to otherwise recover any significant difference between forecast and actual expenses could materially adversely affect the Company's financial condition and results of operations.

Further, the OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors. If actual load or consumption materially falls below projected levels, the Company's revenue and net income for either, or both, of these businesses could be materially adversely affected. Also, the Company's current revenue requirements for these businesses are based on cost and other 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 the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler than normal summer or warmer than normal winter may reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues from the same period of the previous year. The Company's load could also be negatively affected by successful CDM programs whose results exceed forecasted expectations.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB's rate-setting model for distributors requires that the term of a custom rate application (distribution business) be a minimum five-year period. There are risks associated with forecasting over such a long period. For instance, if unanticipated capital expenditures arise that were not contemplated in the Company's most recent rate decision, the Company may be required to incur costs that may not be recoverable until a future period or not recoverable at all in future rates. This could have a material adverse effect on the Company.

The OEB has stated its intention to examine the policies that may apply to transmission rate setting, and this may result in changes to the rate-setting model for transmission services. A change to the rate-setting model for transmission services, such as the introduction of an asymmetrical earnings sharing mechanism, could result in a decrease in the Company's revenues or financial performance.

The OEB approves and periodically, generally on an annual basis, changes the return on equity for transmission and distribution businesses. The OEB may in the future decide to reduce its allowed return on equity for either of these businesses, modify the formula or methodology it uses to determine the return on equity, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

Risks Relating to Capital Expenditures

In order to be recoverable, capital expenditures require the approval of the OEB, either through the approval of capital expenditure plans, rate base or revenue requirements for the purposes of setting transmission and distribution rates, which include the impact of capital expenditures on rate base or cost of service. There can be no assurance that all capital expenditures incurred by Hydro One will be approved by the OEB. Capital cost overruns may not be recoverable in transmission or distribution rates. The Company could incur unexpected capital expenditures in maintaining or improving its assets, particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. There is risk that the OEB may not allow full recovery of such expenditures in the future. To the extent possible, Hydro One aims 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 the Company expects all of its expenditures and regulatory assets to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to a lower than expected approved revenue requirement or rate base, potential asset impairment or charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

Risks Relating to Deferred Tax Asset

As a result of leaving the PILs Regime and entering the Federal Tax Regime, Hydro One recorded a deferred tax asset due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. Management believes this will result in annual net cash savings over the next five years due to the reduction of cash taxes payable by Hydro One associated primarily with a higher capital cost allowance. There is a risk that, in future rate applications, the OEB will reduce the Company's revenue requirement by all or a portion of those net cash savings. If the OEB were to reduce the Company's revenue requirement in this manner, it could have a material adverse effect on the Company.

Risks Relating to Other Applications to the OEB

The Company is also subject to the risk that it will not obtain required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures, and environmental approvals. Decisions to acquire or divest other regulated businesses licensed by the OEB are subject to OEB approval. Accordingly, there is the risk that such matters may not be approved or that unfavourable conditions will be imposed by the OEB.

First Nations and Métis Claims Risk

Some of the Company's current and proposed transmission and distribution assets are or may be located on Reserve (as defined in the *Indian Act* (Canada)) lands, and lands over which First Nations and Métis have Aboriginal, treaty or other legal claims. Although the Company has a recent history of successful negotiations and engagement with First Nations and Métis communities in Ontario, some First Nations and Métis leaders, communities and their members have made assertions related to sovereignty and jurisdiction over Reserve lands and traditional territories and are increasingly willing to assert their claims through the courts, tribunals, or by direct action. These claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may, on occasion, give rise to the Crown's duty to consult and potentially accommodate First Nations and Métis communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult a First Nations or Métis community, or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its members. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued.

Currently, the Ontario Electricity Financial Corporation holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the Ontario Electricity Financial Corporation and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal government (presently Indigenous Affairs and Northern Development Canada) issuing a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, it 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. In either case, the costs relating to these assets could have a material adverse effect on the Company if the costs are not recoverable in future rate orders.

Compliance with Laws and Regulations

Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also "– Health, Safety and Environmental Risk".

For instance, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licenses, with codes and rules issued by the OEB, and with other regulatory requirements, including regulations of the National Energy Board. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with the reliability standards established by the NERC and Northeast Power Coordinating Council, Inc. (NPCC). The incremental costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the OEB will approve the recovery of all of such incremental costs. Failure to obtain such approvals could have a material adverse effect on the Company.

There is the risk that new legislation, regulations or policies will be introduced in the future. These may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates.

Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks, events which originate from third party connected systems, or any other potentially catastrophic events. Although constructed, operated and maintained to industry standards, the Company's facilities may not withstand occurrences of this type in all circumstances. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas. The Company could also be subject to claims for damages caused by its failure to transmit or distribute electricity. Hydro One's risk is partly mitigated because its 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, Hydro One 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 the Company.

Risk Associated with Information Technology Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, maintaining and managing complex information technology systems which are employed to operate and monitor its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks increases its exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and information technology, which only apply to certain of the Company's assets (generally being those whose failure could impact the functioning of the bulk electricity system). The Company may maintain different or lower levels of information technology security for its assets that are not subject to these mandatory standards. Unauthorized access to corporate and information technology systems or cyber-attacks could result in service disruptions and system failures, which could have a material adverse effect on the Company, including as a result of a failure to provide electricity to customers. In addition, in the normal course of its operations, the Company may collect, process or retain access to confidential customer, supplier, counterparty or employee information, which could be exposed in the event of a cyber security incident.

Hydro One mitigates these risks, including through the use of security event management tools on its power and business systems, by separating its transmission and distribution system networks from its other business system networks, by performing scans of its systems for known cyber threats and by providing company-wide awareness training to Hydro One personnel. Hydro One also engages the services of external experts to evaluate the security of its information technology infrastructure and controls. Hydro One performs vulnerability assessments on its critical cyber assets and it ensures security and privacy controls are incorporated into new information technology capabilities. Although these security and system disaster recovery controls are in place, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, 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 the Company.

Workforce Demographic Risk

By the end of 2015, approximately 17% of the Company's employees were eligible for retirement and by the end of 2016, up to approximately 21% could be eligible. These percentages are not evenly spread across the Company's workforce, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During each of 2015 and 2014, approximately 3% of the Company's workforce elected to retire. Accordingly, the Company's continued success will be tied to its ability to attract and retain sufficient qualified staff to replace the capability lost through retirements and to meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry to be highly competitive in the future. Many of the Company's current employees and many of the potential employees it would seek in the future possess skills and experience that would also be highly sought after by other organizations inside and outside the electricity sector. The failure to attract and retain qualified personnel for Hydro One's business could have a material adverse effect on the Company.

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the Power Workers' Union or The Society of Energy Professionals. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company recently reached an agreement with the Power Workers' Union for a renewal collective agreement with a three-year term, covering the period from April 1, 2015 to March 31, 2018 and an early renewal collective agreement with The Society of Energy Professionals with a three-year term, covering the period from April 1, 2016 to March 31, 2019. The Company also reached a renewal collective agreement with the

Canadian Union of Skilled Workers for a three-year term, covering the period from May 1, 2014 to April 30, 2017. Additionally, the Electrical Power Systems Construction Association ("EPSCA") and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a 5-year period covering May 1, 2015 to April 30, 2020. However, there can be no assurance that future collective agreement renewals with these unions or that collective agreements with the other unions with which Hydro One has contractual relationships, will be renewed on acceptable terms. The Company faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its license requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Risk Associated with Arranging Debt Financing

The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One Inc. has substantial amounts of existing debt, including $500 million maturing in 2016, $600 million maturing in 2017, and $750 million maturing in 2018. In addition, from time to time, the Company may draw on its syndicated bank lines and or issue short-term debt under Hydro One Inc.'s $1.5 billion commercial paper program which would need to be paid down. The Company also plans to incur capital expenditures of over $1.6 billion for each of 2016 and 2017. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies and general economic conditions. A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow the required amounts of debt on satisfactory terms could impair its 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 the Company.

Market, Financial Instrument and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The OEB-approved adjustment formula for calculating return on equity in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark rates of return for Government of Canada debt. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining its rate of return would reduce the Company's transmission business' 2017 net income by approximately $22 million and its distribution business' 2017 net income by approximately $14 million. The Company's net income is adversely impacted by rising interest rates as the Company's maturing debt is refinanced at market rates. The Company periodically utilizes 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. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, entering into master agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies 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 the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

Risks Relating to Asset Condition and Capital Projects

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its transmission assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure. However the lack of real time monitoring of distribution assets increases the risk of distribution equipment failure. The connection of large amounts of distributed generation on the distribution network has resulted in more equipment operations than in the past for the Company. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with First Nations and Métis communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. External factors are considered in the Company's planning process. However, if the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce transmission capacity, compromise the reliability of the Company's transmission system or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced.

Health, Safety and Environmental Risk

Hydro One's 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 the Board of Directors that has governance over health, safety and environmental matters. However, given the expansive territory that the Company's system encompasses and the amount of equipment that it owns, the Company cannot guarantee that all such risks will be identified and mitigated without significant cost and expense to the Company. The following are some of the areas that may have a significant impact on the Company's operations.

The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Hydro One currently has a voluntary land assessment and remediation program for off-site migration in place to identify and, where necessary, remediate historical contamination that has resulted from past operational practices and uses of certain long-lasting chemicals at the Company's facilities. Any contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

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.

Although Hydro One is not a large emitter of greenhouse gases, the Company monitors all of these emissions and has a management plan in place to track and report on all sources, including sulphur hexafluoride or "SF6". In addition, the Company recognizes the risks associated with potential climate change and has developed plans to respond as appropriate.

The Company anticipates that all of its future environmental expenditures will continue to be recoverable in future rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are minimally required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2013, and was filed in June 2014, covering a three year period from 2014 to 2016. Hydro One contributed approximately $174 million in respect of 2014, approximately $177 million in respect of 2015, and is expected to contribute approximately $180 million by the end of 2016 to its pension plan to satisfy minimum funding requirements. Contributions beyond 2016 are expected to continue to be significant; actual amounts will depend on investment returns, interest rates, changes in benefits and actuarial assumptions, and may include additional voluntary contributions by the Company from time to time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

The OEB has begun a consultation process that will examine pensions and other post-employment benefits in regulated utilities. See "– Other Post-Employment and Post-Retirement Benefits Risks". The outcome of this consultation process is uncertain and the Company is unable to assess the impact of the potential changes stemming from the review at this time.

Risk of Recoverability of Total Compensation Costs

The Company manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits, subject to restrictions and requirements imposed by the collective bargaining process. Should any element of total compensation costs be disallowed in whole or part by the OEB and not be recoverable from customers in rates, the costs could be material and could lead to changes to the Company's results of operations and decrease net income, which could have a material adverse effect on the Company.

Other Post-Employment and Post-Retirement Benefits Risks

The Company provides other post-employment and post-retirement benefits, including workers compensation benefits and long-term disability benefits to qualifying employees. The OEB has begun a consultation process that will examine pensions and other post-employment benefits in regulated utilities. The objectives of the consultation are to develop standard principles to guide the OEB's review of pension and other post-employment and post-retirement benefits costs in the future, to establish specific information requirements for application and to establish appropriate regulatory mechanisms for cost recovery which can be applied consistently across the gas and electricity sectors for rate-regulated utilities. The outcome of this consultation process is uncertain and the Company is unable to assess the impact of the potential changes stemming from the review at this time. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

Risk Associated with Outsourcing Arrangements

Consistent with Hydro One's strategy of reducing operating costs, it has entered into an outsourcing arrangement with Inergi for the provision of back office services and call centre services. If the outsourcing arrangement or statements of work thereunder are terminated for any reason or expire before a new supplier is selected, the Company could be required to incur significant expenses to transfer to another service provider or insource, which could have a material adverse effect on the Company's business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

The Province owns some of the corridor lands underlying the Company's transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems may increase safety or environmental risks, which could have a material adverse effect on the Company.

Litigation Risks

In the normal course of the Company's operations, it may become involved in, be named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company.

Risks Relating to the Company's Relationship with the Province

Ownership by the Province and Voting Power; Share Ownership Restrictions

The Province currently owns approximately 84% of the common shares of Hydro One. The *Electricity Act* restricts the Province from selling voting securities of Hydro One (including common shares) of any class or series if it would own less than 40% of the outstanding number of voting securities of that class or series after the sale and in certain circumstances also requires the Province to take steps to maintain that level of ownership. Accordingly, the Province is expected to continue to maintain a significant ownership interest in voting securities of Hydro One for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject to the restrictions in the governance agreement entered into between Hydro One and the Province dated November 5, 2015 ("Governance Agreement"; available on SEDAR at www.sedar.com). While, with respect to its ownership interest in Hydro One, the Province has agreed to engage in the business and affairs of Hydro One only as an investor and not as a manager, and has stated its intention to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, the Governance Agreement preserves the Province's right to vote its common shares in its sole interest, which may not be aligned with the interests of the Company's other shareholders.

The share ownership restrictions in the *Electricity Act* ("Share Ownership Restrictions") and the Province's significant ownership of common shares of Hydro One together effectively prohibit one or more persons acting together from acquiring control of Hydro One. They also may limit or discourage transactions involving other fundamental changes to Hydro One and the ability of other shareholders to successfully contest the election of the directors proposed for election pursuant to the Governance Agreement. The Share Ownership Restrictions may also discourage trading in, and may limit the market for, the common shares and other voting securities.

Continued Influence by the Province

Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of the Company as an investor and not as a manager, there is a risk that the Province's engagement in the business and affairs of the Company as an investor will be informed by its own policy objectives and may influence the conduct of the business and affairs of the Company in ways that may not be aligned with the interests of other shareholders.

Nomination of Directors and Confirmation of Chief Executive Officer and Chair

Although director nominees are required to be independent of both the Company and the Province pursuant to the Governance Agreement, there is a risk that the Province will nominate or confirm individuals who satisfy the independence requirements but who it considers are disposed to support and advance its policy objectives and give disproportionate weight to the Province's interests in exercising their business judgment and balancing the interests of the stakeholders of Hydro One. This, combined with the fact certain matters require a two-thirds vote of the Board of Directors, could allow the Province to unduly influence certain Board actions such as confirmation of the Chair and confirmation of the Chief Executive Officer.

Board Removal Rights

Under the Governance Agreement, the Province has the right to withhold from voting in favour of all director nominees and has the right to seek to remove and replace the entire Board of Directors, including in each case its own director nominees but excluding the Chief Executive Officer and, at the Province's discretion, the Chair. In exercising these rights in any particular circumstance, the Province is entitled to vote in its sole interest, which may not be aligned with the interests of other shareholders.

More Extensive Regulation

Although under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One as an investor and not as a manager and has stated that its intention is to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, there is a risk that the Province will exercise its legislative and regulatory power to achieve policy objectives in a manner that has a material adverse effect on the Company.

Prohibitions on Selling the Company's Transmission or Distribution Business

The *Electricity Act* prohibits the Company from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the OEB. There is a risk that these prohibitions may limit the ability of the Company to engage in sale transactions involving a substantial portion of either system, even where such a transaction may otherwise be considered to provide substantial benefits to the Company and the holders of the common shares.

Future Sales of Common Shares by the Province

The Province has indicated that it currently intends to sell further common shares of Hydro One over time, until it holds approximately 40% of the common shares, subject to the selling restrictions agreed with the Underwriters. The registration rights agreement between Hydro One and the Province dated November 5, 2015 (available on SEDAR at www.sedar.com) also grants the Province the right to request that Hydro One file one or more prospectuses and take other procedural steps to facilitate secondary offerings by the Province of the common shares of Hydro One. Future sales of common shares of Hydro One by the Province, or the perception that such sales could occur, may materially adversely affect market prices for these common shares and impede Hydro One's ability to raise capital through the issuance of additional common shares, including the number of common shares that Hydro One may be able to sell at a particular time or the total proceeds that may be realized.

Limitations on Enforcing the Governance Agreement

The Governance Agreement includes commitments by the Province restricting the exercise of its rights as a holder of voting securities, including with respect to the maximum number of directors that the Province may nominate and on how the Province will vote with respect to other director nominees. Hydro One's ability to obtain an effective remedy against the Province, if the Province were not to comply with these commitments, is limited as a result of the *Proceedings Against the Crown Act* (Ontario). This legislation provides that the remedies of injunction and specific performance are not available against the Province, although a court may make an order declaratory of the rights of the parties, which may influence the Province's actions. A remedy of damages would be available to Hydro One, but damages may not be an effective remedy, depending on the nature of the Province's non-compliance with the Governance Agreement.

Critical Accounting Estimates

The preparation of Hydro One Consolidated Financial Statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. Hydro One bases its estimates and judgments 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 judgments about the carrying values of assets and liabilities, as well as identifying and assessing the Company's accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. Hydro One has identified the following critical accounting estimates used in the preparation of its Consolidated Financial Statements:

Revenues

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. Unbilled revenues are based on an estimate of electricity delivered determined by historical trends of consumption and are estimated at the end of each month. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Accounts Receivable and Allowance for Doubtful Accounts

In 2015, the Company revised its method to estimate the unbilled accounts receivable based on new technology implemented to enhance the estimation process. This change has been accounted for on a prospective basis in the consolidated financial statements at December 31, 2015. At December 31, 2015, the change in estimate reduced unbilled accounts receivable by approximately $121 million, with a corresponding offset to various components of the retail settlement variance accounts (RSVA) regulatory asset. The change in estimate had no impact on 2015 revenues or net income.

The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs.

Regulatory Assets and Liabilities

Hydro One's regulatory assets represent certain amounts receivable from future electricity customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, share-based compensation costs, and environmental liabilities. The Company's regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to OEB deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates 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 allow the inclusion of a regulatory asset or liability in future electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

Environmental Liabilities

Hydro One records a liability for the estimated 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. 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. 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. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

Hydro One's employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to the Company's current and retired employees. Employee future benefits costs are included in Hydro One's labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions affect the benefit obligation of the employee future benefits and the amounts that will be charged to results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

Weighted Average Discount Rate

The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate at December 31, 2015 remained at 4.00% for pension benefits whereas it increased to 4.10% (from 4.00% used at December 31, 2014) for the post-retirement and post-employment plans. The increase in the discount rate has resulted in a corresponding decrease in employee future benefits liabilities for the post-retirement and post-employment plans for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets

The expected rate of return on pension plan assets is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's current investment policy.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects the Company's long-term expectations. We believe that this assumption is reasonable because, with the pension plan'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 lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 1.70% per annum as at December 31, 2014 to approximately 1.50% per annum as at December 31, 2015. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2015.

Mortality Assumptions

The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption at December 31, 2015 is based on the final tables issued by the Canadian Institute of Actuaries (for public sector, with projection scale CPM-B and no adjustment due to pension size). This is the same assumption as was used as of December 31, 2014.

Rate of Increase in Health Care Cost Trends

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and 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 a $22 million increase in 2015 interest cost plus service cost, and a $252 million increase in the year-end 2015 benefit liability.

Asset Impairment

Within Hydro One's regulated businesses, the carrying costs of most of the long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-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. We regularly monitor the assets of the

Company's unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2015, no asset impairment had been recorded for assets within Hydro One's regulated or unregulated businesses.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Hydro One has concluded that goodwill was not impaired at December 31, 2015. 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.

Disclosure Controls And Internal Controls Over Financial Reporting

Internal controls have been documented and tested for adequacy and effectiveness, and continue to be refined over all business processes.

In compliance with the requirements of National Instrument 52-109, the Company's Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2015, together with other financial information included in the Company's securities filings. The Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to the Company is made known within the Company. Further, the Certifying Officers have certified that internal controls over financial reporting (ICFR) have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of the Company's DC&P and ICFR, the Certifying Officers concluded that the Company's DC&P and ICFR were effective as at December 31, 2015.

New Accounting Pronouncements

In January 2015, the Financial Accounting Standards Board (FASB) issued an accounting standards update that eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary and to show the item separately in the income statement. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company does not anticipate that the adoption of this update will have a significant impact on its consolidated financial statements.

In February 2015, the FASB issued an accounting standards update that provides guidance about the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company does not anticipate that the adoption of this update will have a significant impact on its consolidated financial statements.

In April 2015, the FASB issued an accounting standards update that requires debt issuance costs related to a recognized debt liability to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability. The recognition and measurement guidance for debt issuance costs are not affected. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. Upon adoption of this update in the first quarter of 2016, the Company's deferred debt issuance costs that are currently presented under other long-term assets will be reclassified as a deduction from the carrying amount of long-term debt.

In April 2015, the FASB issued an accounting standards update that permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure the defined benefit plan assets and obligations using the month-end that is closest to the entity's fiscal year-end. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company does not anticipate that the adoption of this update will have a significant impact on its consolidated financial statements.

In April 2015, the FASB issued an accounting standards update that provides guidance to customers about whether a cloud computing arrangement includes a software license, as well as the related accounting for the arrangement. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company is currently assessing the impact of adoption of this update on its consolidated financial statements.

In August 2015, the FASB issued an accounting standards update that defers by one year the effective date of a revenue recognition standard issued in 2014 to January 1, 2018. The standard provides guidance on revenue recognition that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The Company is currently assessing the impact of adoption of this update on its consolidated financial statements.

In September 2015, the FASB issued an accounting standards update that requires an acquirer to recognize adjustments to provisional amounts that are identified during the measurement period of a business combination in the reporting period in which the adjustment amounts are determined. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016 for measurement adjustments related to business combinations.

In November 2015, the FASB issued an accounting standards update that requires all deferred tax assets and liabilities to be classified as noncurrent on the balance sheet. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2017. Upon adoption of this update in the first quarter of 2017, the current portions of the Company's deferred income tax assets and liabilities will be reclassified as long-term assets and liabilities on the consolidated Balance Sheets.

In January 2016, the FASB issued an accounting standards update that requires equity investments to be measured at fair value with changes in fair value recognized in net income, and requires enhanced disclosures and presentation of financial assets and liabilities in the financial statements. This update also simplifies the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2018. The Company is currently assessing the impact of adoption of this update on its consolidated financial statements.

Other Matters

Appointment of New Board of Directors

In 2015, the Province appointed a fully independent Board of Directors to govern Hydro One as a publicly traded company, with a renewed focus on customer service excellence, improved performance and reliability, and growing shareholder value. Each of the directors, including Canadian business leaders, electricity sector experts, corporate directors and a former provincial Ombudsman, was selected based upon their independence, commercial experience, and specific expertise.

Appointment of President and Chief Executive Officer

In August 2015, the Company's Board of Directors announced the appointment of Mayo Schmidt as Hydro One's new President and Chief Executive Officer, effective September 3, 2015. Mr. Schmidt was most recently the Chief Executive Officer of Viterra Inc.

Appointment of Chief Financial Officer

In June 2015, Mr. Michael Vels was appointed to the position of Chief Financial Officer of Hydro One, effective July 1, 2015. Mr. Vels was most recently the Chief Financial Officer at Maple Leaf Foods Inc.

Appointment of Hydro One Ombudsman

In October 2015, the Hydro One Board of Directors announced the appointment of Fiona Crean to the role of Ombudsman for Hydro One, effective November 17, 2015. Ms. Crean most recently served as the City of Toronto's Ombudsman, and has worked in the area of dispute resolution and complaints investigation for more than 25 years. Ms. Crean will report directly to the Hydro One Board of Directors.

Summary of Fourth Quarter Results of Operations

Quarter ended December 31 *(millions of Canadian dollars, except per share amounts)*	2015	2014	Change
Revenues			
Distribution	1,148	1,268	(9.5%)
Transmission	361	382	(5.5%)
Other	13	12	8.3%
	1,522	1,662	(8.4%)
Costs			
Purchased power	786	893	(12.0%)
OM&A			
Distribution	146	148	(1.4%)
Transmission	128	86	48.8%
Other	27	13	107.7%
	301	247	21.9%
Depreciation and amortization	193	190	1.6%
	1,280	1,330	(3.8%)
Income before financing charges and income taxes	242	332	(27.1%)
Financing charges	94	98	(4.1%)
Income before income taxes	148	234	(36.8%)
Income tax expense	1	15	(93.3%)
Net income	147	219	(32.9%)
Net income attributable to common shareholders of Hydro One	143	216	(33.8%)
Basic and diluted EPS	$ 0.26	$ 0.45	(42.2%)
Capital investments			
Distribution	198	211	(6.2%)
Transmission	251	265	(5.3%)
Other	2	2	–
	451	478	(5.6%)

Net Income and EPS

The changes to net income and EPS were primarily due to the following:

- Milder weather resulted in a decrease in transmission revenues, mainly due to lower average monthly Ontario 60-minute peak demand, and lower net distribution revenues; and
- Although expenses related to stabilization of the Company's customer information system were significantly lower than last year, OM&A costs increased from last year, primarily due to:
  - expenses related to write-offs of project and inventory costs due to revisions of asset replacement strategies;
  - higher storm restoration efforts due to multiple windstorms in the fourth quarter of 2015;
  - timing of preventative maintenance on grid infrastructure;
  - insurance proceeds receipts in 2014 that did not re-occur in 2015; and
  - expenditures related to integration of acquired local distribution companies.

Income tax expense for the quarter was reduced by an income tax recovery of $19 million due to tax benefits related to the IPO.

Excluding this effect, the fourth quarter 2015 effective tax rate would have been approximately 13.8% compared to the fourth quarter 2014 effective tax rate of approximately 6.6%.

Revenues

The quarterly decrease of $21 million or 5.5% in transmission revenues was primarily due to lower average monthly Ontario 60-minute peak demand associated with unseasonably warm weather during the fourth quarter of 2015.

The quarterly decrease of $120 million or 9.5% in distribution revenues was primarily due to lower purchased power costs, the spin-off of Hydro One Brampton, and lower consumption due primarily to milder weather, partially offset by higher OEB-approved distribution rates.

OM&A Costs

The quarterly increase of $42 million or 48.8% in transmission OM&A costs was primarily due to the following:

- expenses related to write-offs of project and inventory costs due to revisions of asset replacement strategies;
- higher volumes of preventative and corrective station maintenance on power equipment;
- insurance proceeds received in the fourth quarter of 2014 related to 2013 floods at the Company's Richview and Manby transformer stations which were recorded as a reduction in 2014 OM&A costs;
- higher expenditures during 2015 related to work required to adhere to the NERC Cyber Security standards; and
- increased expenditures related to forestry control and line clearing on the Company's transmission rights-of-way.

The decrease of $2 million or 1.4% in distribution OM&A costs during the fourth quarter of 2015 was primarily due to the following:

- a decrease in bad debt expense and lower expenditures related to remediation of the Company's customer information system; and
- decreased vegetation management expenditures relating to distribution line clearing and forestry control; partially offset by
- increased costs associated with responding to power quality-related issues and outages as a result of multiple wind storms which occurred during the fourth quarter of 2015.

Depreciation and Amortization

The increase of $3 million or 1.6% in depreciation and amortization costs during the fourth quarter of 2015 compared to last year was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its multi-year capital investment program.

Income Taxes

The decrease of $14 million in income tax expense for the fourth quarter of 2015 compared to 2014 was due to lower income before taxes, in addition to the positive effect of an income tax recovery associated with the step-up of the tax basis of the assets of Hydro One Inc. and its subsidiaries to fair market value in excess of the Departure Tax incurred when Hydro One exited the PILs Regime.

For the fourth quarter of 2015, the Company realized an effective tax rate of approximately 0.7%, compared to approximately 6.6% realized for the fourth quarter of 2014. The difference in the effective tax rates is due primarily to the income tax recovery on the revaluation of the assets of Hydro One on exiting the PILs Regime, partially offset by a decrease in accelerated capital cost allowance over depreciation recognized in 2014 for certain classes of assets.

Capital Investments

During the fourth quarter of 2015, the Company made capital investments totalling $451 million and placed $607 million of new assets in-service. Capital investments in the transmission system during the fourth quarter included equipment replacements at the Bruce, Richview and Pickering Transmission Stations, and continued work on the Company's major inter-area network and local area supply projects, including the Clarington Transmission Station and Guelph Area Transmission Refurbishment projects.

Capital investments in the distribution system during the fourth quarter included capital work related to station refurbishment programs and wood utility pole replacements, continued investments in new customer connections and upgrades, and increased storm restoration work as a result of two significant wind storms during the fourth quarter of 2015.

Forward-looking Statements And Information

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to: expectations regarding energy-related revenues and profit and their trend; statements regarding the Company's transmission and distribution rates resulting from rate applications; statements about

CDM; statements regarding the Company's liquidity and capital resources and operational requirements; statements about the standby credit facilities; expectations regarding the Company's financing activities; statements regarding the Company's maturing debt; statements regarding 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 investments; statements regarding expected future capital and development investments, the timing of these expenditures and the Company's investment plans; statements regarding contractual obligations and other commercial commitments; statements related to the OEB; statements regarding future pension contributions, the pension plan and actuarial valuation; expectations related to workforce demographics; statements about the outsourcing arrangements with Inergi and Brookfield; expectations regarding work and costs of compliance with environmental and health and safety regulations; statements related to critical accounting estimates, including employee future benefits and expectations regarding regulatory assets and liabilities; statements about non-GAAP measures; statements regarding recent accounting-related guidance; statements about internal controls; expectations about effect of interest rates; statements related to Hydro One Brampton; statements about collective agreements; expectations regarding taxes; statements related to future sales of shares of Hydro One; statements related to the Company's relationship with the Province; statements about share-based compensation; statements related to claims; statements regarding the role of Hydro One's Ombudsman; and statements related to the Company's acquisitions and integrations, including statements about Great Lakes Power Transmission LP, Woodstock Hydro, Haldimand Hydro, and Norfolk Power. 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. Hydro One does not intend, and it disclaims 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 and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's Distribution and Transmission Businesses; continued use of US GAAP; 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 the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and 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:

- risks associated with the Province's significant share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on Reserves (as defined in the Indian Act (Canada));
- the risks associated with information system security and with maintaining a complex information technology system infrastructure;
- the risks related to the Company's workforce demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;

- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- changes in benefits and changes in actuarial assumptions;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace some or all of the functions currently outsourced if either of the Company's agreements with Inergi or Brookfield are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions 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 MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future expenditures, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One is available on SEDAR at www.sedar.com.

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 Limited (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.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, 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 11, 2016.

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 (2013), 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, 2015. The effectiveness of these internal controls is reported to the Audit Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the shareholders of the Company. 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 Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit 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 Committee, with and without the presence of management, to discuss their audit findings.

The President and Chief Executive Officer and the 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's management:

Mayo Schmidt
President and Chief
Executive Officer

Michael Vels
Chief Financial Officer

Independent Auditors' Report

To the Shareholders of Hydro One Limited

We have audited the accompanying Consolidated Financial Statements of Hydro One Limited, which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014, the consolidated statements of operations and comprehensive income, changes in 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 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 Limited as at December 31, 2015 and December 31, 2014, 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 11, 2016

Consolidated Statements of Operations and Comprehensive Income

For the years ended December 31, 2015 and 2014

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2015	2014
Revenues		
Distribution (includes $159 related party revenues; 2014 – $159) *(Note 23)*	4,949	4,903
Transmission (includes $1,554 related party revenues; 2014 – $1,567) *(Note 23)*	1,536	1,588
Other	53	57
	6,538	6,548
Costs		
Purchased power (includes $2,335 related party costs; 2014 – $2,633) *(Note 23)*	3,450	3,419
Operation, maintenance and administration *(Note 23)*	1,135	1,192
Depreciation and amortization *(Note 5)*	759	722
	5,344	5,333
Income before financing charges and income taxes	1,194	1,215
Financing charges *(Note 6)*	376	379
Income before income taxes	818	836
Income taxes *(Notes 7, 23)*	105	89
Net income	713	747
Other comprehensive income	1	–
Comprehensive income	714	747
Net income attributable to:		
Noncontrolling interest *(Note 22)*	10	(2)
Preferred shareholders	13	18
Common shareholders	690	731
	713	747
Comprehensive income attributable to:		
Noncontrolling interest *(Note 22)*	10	(2)
Preferred shareholders	13	18
Common shareholders	691	731
	714	747
Earnings per common share *(Note 20)*		
Basic	$ 1.39	$ 1.53
Diluted	$ 1.39	$ 1.53
Dividends per common share declared *(Note 19)*	$ 1.83	$ 0.56

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets

At December 31, 2015 and 2014

December 31 (millions of Canadian dollars)	2015	2014
Assets		
Current assets:		
Cash and cash equivalents *(Note 13)*	94	100
Accounts receivable (net of allowance for doubtful accounts – $61; 2014 – $66) *(Note 8)*	776	1,016
Due from related parties *(Note 23)*	191	224
Regulatory assets *(Note 11)*	36	31
Materials and supplies	21	23
Deferred income tax assets *(Note 7)*	19	19
Derivative instruments *(Note 13)*	–	2
Prepaid expenses and other assets	29	35
	1,166	1,450
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	26,070	25,356
Less: accumulated depreciation	9,414	9,134
	16,656	16,222
Construction in progress	1,155	1,025
Future use land, components and spares	157	154
	17,968	17,401
Other long-term assets:		
Regulatory assets *(Note 11)*	3,015	3,200
Deferred income tax assets *(Note 7)*	1,636	7
Intangible assets (net of accumulated amortization – $274; 2014 – $305) *(Note 10)*	336	276
Goodwill *(Note 4)*	163	173
Deferred debt issuance costs	34	36
Derivative instruments *(Note 13)*	1	–
Other	9	7
	5,194	3,699
Total assets	24,328	22,550

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets (continued)

At December 31, 2015 and 2014

December 31 (millions of Canadian dollars, except number of shares)	2015	2014
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	–	2
Short-term notes payable *(Notes 12, 13)*	1,491	–
Accounts payable	155	173
Accrued liabilities *(Notes 15, 16)*	598	611
Due to related parties *(Note 23)*	138	227
Accrued interest	96	100
Regulatory liabilities *(Note 11)*	19	47
Derivative instruments *(Note 13)*	–	3
Long-term debt payable within one year (includes $nil measured at fair value; 2014 – $252) *(Notes 12, 13)*	500	552
	2,997	1,715
Long-term debt (includes $51 measured at fair value; 2014 – $nil) *(Notes 12, 13)*	8,224	8,373
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	1,560	1,533
Pension benefit liability *(Note 15)*	952	1,236
Regulatory liabilities *(Note 11)*	236	168
Deferred income tax liabilities *(Note 7)*	207	1,313
Environmental liabilities *(Note 16)*	185	221
Net unamortized debt premiums	17	18
Asset retirement obligations *(Note 17)*	9	9
Long-term accounts payable and other liabilities	17	17
	3,183	4,515
Total liabilities	14,404	14,603
Contingencies and Commitments (Notes 25, 26)		
Subsequent Events (Note 28)		
Preferred shares *(Notes 18, 19)*	–	323
Noncontrolling interest subject to redemption *(Note 22)*	23	21
Equity		
Common shares *(Notes 18, 19)*	5,623	3,314
Preferred shares *(Notes 18, 19)*	418	–
Additional paid-in capital *(Note 21)*	10	–
Retained earnings	3,806	4,249
Accumulated other comprehensive loss	(8)	(9)
Total Hydro One shareholders' equity	9,849	7,554
Noncontrolling interest *(Note 22)*	52	49
Total equity	9,901	7,603
	24,328	22,550

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

Consolidated Statements of Changes in Equity

For the years ended December 31, 2015 and 2014

Year ended December 31, 2015 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Hydro One Shareholders' Equity	Non-controlling Interest *(Note 22)*	Total Equity
January 1, 2015	3,314	–	–	4,249	(9)	7,554	49	7,603
Net income	–	–	–	703	–	703	7	710
Other comprehensive income	–	–	–	–	1	1	–	1
Distributions to noncontrolling interest	–	–	–	–	–	–	(4)	(4)
Dividends on preferred shares	–	–	–	(13)	–	(13)	–	(13)
Dividends on common shares	–	–	–	(875)	–	(875)	–	(875)
Hydro One Brampton spin-off *(Note 4)*	(196)	–	–	(258)	–	(454)	–	(454)
Pre-IPO Transactions *(Notes 1, 18)*	2,505	418	–	–	–	2,923	–	2,923
Stock-based compensation *(Note 21)*	–	–	10	–	–	10	–	10
December 31, 2015	5,623	418	10	3,806	(8)	9,849	52	9,901

Year ended December 31, 2014 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Hydro One Shareholders' Equity	Non-controlling Interest *(Note 22)*	Total Equity
January 1, 2014	3,314	–	–	3,787	(9)	7,092	–	7,092
Net income	–	–	–	749	–	749	(1)	748
Other comprehensive income	–	–	–	–	–	–	–	–
Amount contributed by noncontrolling interest	–	–	–	–	–	–	50	50
Dividends on preferred shares	–	–	–	(18)	–	(18)	–	(18)
Dividends on common shares	–	–	–	(269)	–	(269)	–	(269)
December 31, 2014	3,314	–	–	4,249	(9)	7,554	49	7,603

See accompanying notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the years ended December 31, 2015 and 2014

Year ended December 31 (millions of Canadian dollars)	2015	2014
Operating activities		
Net income	713	747
Environmental expenditures	(19)	(18)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	668	641
Regulatory assets and liabilities	(3)	(69)
Deferred income taxes *(Note 7)*	(2,844)	10
Other	24	–
Changes in non-cash balances related to operations *(Note 24)*	208	(55)
Net cash from (used in) operating activities	(1,253)	1,256
Financing activities		
Long-term debt issued	350	628
Long-term debt retired	(585)	(776)
Short-term notes issued	1,491	–
Common shares issued	2,600	–
Dividends paid	(888)	(287)
Amount contributed by noncontrolling interest *(Note 22)*	–	72
Distributions paid to noncontrolling interest	(5)	–
Change in bank indebtedness	(2)	(29)
Other	(7)	(3)
Net cash from (used in) financing activities	2,954	(395)
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(1,595)	(1,481)
Intangible assets	(37)	(23)
Capital contributions received *(Note 24)*	62	–
Acquisition of Haldimand Hydro *(Note 4)*	(66)	–
Acquisition of Woodstock Hydro *(Note 4)*	(24)	–
Investment in Hydro One Brampton *(Note 4)*	(53)	–
Acquisition of Norfolk Power *(Note 4)*	–	(66)
Proceeds from investment	–	250
Other	6	(6)
Net cash used in investing activities	(1,707)	(1,326)
Net change in cash and cash equivalents	(6)	(465)
Cash and cash equivalents, beginning of year	100	565
Cash and cash equivalents, end of year	94	100

See accompanying notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

For the years ended December 31, 2015 and 2014

1. Description of The Business

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario).

On October 31, 2015, the Company acquired Hydro One Inc., a company previously wholly-owned by the Province of Ontario (Province). The acquisition of Hydro One Inc. by Hydro One was accounted for as a common control transaction and Hydro One is a continuation of business operations of Hydro One Inc. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

In November 2015, Hydro One and the Province completed an initial public offering (IPO) on the Toronto Stock Exchange of 15% of its 595 million outstanding common shares. The proceeds of the offering were received by the Province. All of the regulated business and outstanding publicly issued notes and debentures of Hydro One remain at the Company's wholly owned subsidiary Hydro One Inc. At December 31, 2015, the Province owns 84% of Hydro One. See Note 18 for further details regarding the reorganization of Hydro One.

2. Significant Accounting Policies

Basis of Consolidation and Preparation

These Consolidated Financial Statements have been presented in a manner similar to the pooling-of-interests method. The financial statements consist of the results of operations of Hydro One Inc. prior to October 31, 2015, and the consolidated results of operations of Hydro One from the date of incorporation on August 31, 2015 to December 31, 2015, which include the results of Hydro One Inc. subsequent to its acquisition on October 31, 2015. All periods have been combined using historical amounts. The comparative information consists of the results of Hydro One Inc. as at and for the year ended December 31, 2014. In addition, Hydro One's issued and outstanding common shares prior to October 31, 2015 have been retroactively adjusted for the purposes of presentation to reflect the effects of the acquisition of Hydro One Inc. using the exchange ratio established for the acquisition. The accompanying combined consolidated and consolidated financial statements are referred to as "consolidated" for all periods presented. Intercompany transactions and balances have been eliminated.

On August 31, 2015, Hydro One Inc. completed the spin-off of its subsidiary, Hydro One Brampton Networks Inc. (Hydro One Brampton) to the Province. See note 4 – Business Combinations. These Consolidated Financial Statements include the results of operations of Hydro One Brampton up to August 31, 2015.

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.

Hydro One performed an evaluation of subsequent events through to February 11, 2016, 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 28 – 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 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, 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.

Rate Setting

The Company's Transmission Business consists of the transmission business of Hydro One Inc., which includes the transmission business of its subsidiary, Hydro One Networks Inc. (Hydro One Networks), as well as its 66% interest in B2M Limited Partnership (B2M LP). The

Company's Distribution Business consists of the distribution business of Hydro One Inc., which includes the distribution businesses of Hydro One Networks, Haldimand County Utilities Inc. (Haldimand Hydro), Hydro One Remote Communities Inc. (Hydro One Remote Communities), and Woodstock Hydro Holdings Inc. (Woodstock Hydro).

The Ontario Energy Board (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.

Transmission

On January 8, 2015, pursuant to an application filed with the OEB, the OEB approved the 2015 Hydro One transmission rates revenue requirement, excluding the B2M LP revenue requirement, of $1,477 million.

On June 30, 2015, B2M LP updated its application (originally filed March 30, 2015) with the OEB for 2015-2019 transmission rates, requesting approval of revenue requirement of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. On December 29, 2015, the OEB issued a Decision and Order approving the 2015-2019 rates revenue requirement, and on January 14, 2016, the OEB approved the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes.

Distribution

On March 12, 2015, the OEB issued a Decision and Rate Order approving a revenue requirement of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The revenue requirements for 2016 and 2017 are estimates that may change based on 2016 and 2017 Rate Orders. On April 23, 2015, the Final Rate Order for 2015 rates was approved by the OEB.

On September 24, 2014, Hydro One Remote Communities filed an Incentive Regulation Mechanism application with the OEB for 2015 rates, seeking approval for increased base rates for the distribution and generation of electricity of 1.7%. On March 19, 2015, the OEB approved an increase of approximately 1.6% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2015.

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 attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. Unbilled revenues are based on an estimate of electricity delivered determined by historical trends of consumption and are estimated at the end of each month. The unbilled revenue estimate is affected by energy consumption, weather, 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.

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 recorded at their estimated value. 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 Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The existing allowance for doubtful accounts will continue to be affected by changes in volume, prices and economic conditions.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to shareholders of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income (loss) and other comprehensive income (loss) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Income Taxes

By virtue of being wholly owned by the Province, Hydro One was exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (Federal Tax Regime). However, under the *Electricity Act*, Hydro One was required to make payments in lieu of tax (PILs) to the Ontario Electricity Financial Corporation (OEFC) (PILs Regime). The PILs were, in general, based on the amount of tax that Hydro One would otherwise be liable to pay under the Federal Tax Regime if it was not exempt from taxes under those statutes.

In connection with the IPO of Hydro One, Hydro One's exemption from tax under the Federal Tax Regime ceased to apply. Upon exiting the PILs Regime, Hydro One is required to make corporate income tax payments to the Canada Revenue Agency (CRA) under the Federal Tax Regime.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as 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 Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

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 as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net 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, 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 fibre optic and microwave radio systems, 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 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 financing costs are a reduction of 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, 2015. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Transmission	56 years	1% – 2%	2%
Distribution	46 years	1% – 7%	2%
Communication	16 years	1% – 15%	6%
Administration and service	18 years	1% – 20%	6%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rate for computer applications software and other intangible assets is 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 asset retirement obligations have 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, 2015, based on the qualitative assessment performed as at September 30, 2015, 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, 2015.

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, the Company evaluates whether impairment may exist by estimating 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, 2015 and 2014, 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 issuance costs on the Consolidated Balance Sheets. Deferred debt issuance 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). 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. All financial instrument transactions are recorded at trade date.

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.

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 on 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 Statements 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 which 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, 2015 or 2014.

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 defined benefit 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. Defined benefit 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 post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

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.

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.

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

Former employees of Haldimand Hydro and Woodstock Hydro participate in the Ontario Municipal Employees Retirement System Fund (OMERS Plan), a multiemployer, contributory, defined benefit public sector pension fund. Former employees of Norfolk Power Inc. (Norfolk Power) ceased to contribute to the OMERS Plan upon integration of Norfolk Power into Hydro One Networks in September 2015. These employees are now included in Hydro One's defined benefit pension plan. OMERS Plan provides retirement pension payments based on members' length of service and salary. Both the 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. The OMERS Plan 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 employees of Haldimand Hydro and Woodstock Hydro. 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.

Stock-Based Compensation

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period, as management considers it to be probable that such costs will be recovered in the future through the rate-setting process.

The Company also records the liabilities associated with its Directors' Deferred Share Unit (DSU) Plan at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Company's common share closing price at the end of each reporting period.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. 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 judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty 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 contaminated land assessment and remediation 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

Asset retirement obligations 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 asset retirement obligations 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 asset retirement obligation, 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 asset retirement obligation 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 asset retirement obligations, 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 asset retirement obligations currently exist 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 asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Company's asset retirement obligations 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

Recent Accounting Guidance Not Yet Adopted

In January 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items. This ASU eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary and to show the item separately in the income statement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Company's consolidated financial statements.

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides guidance about the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. This ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The recognition and measurement guidance for debt issuance costs are not affected. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. Upon adoption of this ASU in the first quarter of 2016, the Company's deferred debt issuance costs that are currently presented under other long-term assets will be reclassified as a deduction from the carrying amount of long-term debt.

In April 2015, the FASB issued ASU 2015-04, Compensation – Retirement Benefits (Topic 715): Practical Expedient for the Measurement Date of an Employer's Defined Benefit Obligation and Plan Assets. This ASU permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure the defined benefit plan assets and obligations using the month-end that is closest to the entity's fiscal year-end. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-05, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement. This ASU provides guidance to customers about whether a cloud computing arrangement includes a software license, as well as the related accounting for the arrangement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The Company is currently assessing the impact of adoption of this ASU on its consolidated financial statements.

In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date. This ASU defers by one year the effective date of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) issued by the FASB in May 2014. ASU 2014-09 provides guidance on revenue recognition that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The guidance in ASU 2014-09 is now effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company is currently assessing the impact of adoption of ASU 2014-09 on its consolidated financial statements.

In September 2015, the FASB issued ASU 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments. The amendments in this ASU require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period of a business combination in the reporting period in which the adjustment amounts are determined. The amendments in this update require that the acquirer to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. Upon adoption of this ASU in the first quarter of 2016, the Company will apply the guidance in this ASU to future measurement adjustments related to business combinations, as applicable.

In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes. The amendments in this ASU require that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Upon adoption of this ASU in the first quarter of 2017, the current portions of the Company's deferred income tax assets and liabilities will be reclassified as noncurrent assets and liabilities on the consolidated Balance Sheets.

In January 2016, the FASB issued ASU 2016-01, Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities. This ASU requires equity investments to be measured at fair value with changes in fair value recognized in net income, and requires enhanced disclosures and presentation of financial assets and liabilities in the financial statements. This ASU also simplifies the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company is currently assessing the impact of adoption of this ASU on its consolidated financial statements.

4. Business Combinations

Acquisition of Woodstock Hydro

On October 31, 2015, Hydro One acquired 100% of the common shares of Woodstock Hydro, an electricity distribution company located in southwestern Ontario. The total purchase price for Woodstock Hydro was approximately $32 million.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Cash and cash equivalents	3
Working capital	4
Property, plant and equipment	28
Intangible assets	1
Deferred income tax assets	2
Goodwill	17
Long-term debt	(17)
Other long-term liabilities	(2)
Post-retirement and post-employment benefit liability	(1)
Derivative instruments	(3)
	32

The preliminary determination of the fair value of assets acquired and liabilities assumed has been based upon management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. Due to the timing of the transaction, the Company has not yet completed the final fair value measurements as at December 31, 2015. In addition, the purchase agreement provides for final purchase price adjustments based on agreed working capital and other balances at the acquisition date which have not yet been finalized. The Company will continue to review information and perform further analysis prior to finalizing the total purchase price and the fair values of the assets acquired and liabilities assumed. The actual total purchase price and the fair values of the assets acquired and liabilities assumed may differ from the amounts above.

Goodwill of approximately $17 million arising from the Woodstock Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Woodstock Hydro. All of the goodwill was assigned to Hydro One's Distribution Business segment. Woodstock Hydro contributed revenues of $12 million and net income of $2 million to the Company's consolidated financial results for the year ended December 31, 2015. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Woodstock Hydro's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2015 and therefore, has not been disclosed on a pro forma basis.

Hydro One Brampton Spin-off

On August 31, 2015, Hydro One completed the spin-off of its subsidiary, Hydro One Brampton. The spin-off was accounted as a non-monetary, nonreciprocal transfer with the Province, based on its carrying values at August 31, 2015. Transactions that immediately preceded the spin-off as well as the spin-off were as follows:

- Hydro One subscribed for 357 common shares of Hydro One Brampton for an aggregate subscription price of $53 million;
- Hydro One transferred to a company wholly owned by the Province all the issued and outstanding shares of Hydro One Brampton as a dividend-in-kind; and all of the long-term intercompany debt in aggregate principal amount of $193 million plus accrued interest of $3 million owed by Hydro One Brampton to Hydro One as a return of stated capital of $196 million on its common shares.

In connection with the Hydro One Brampton spin-off, the following assets and liabilities of Hydro One Brampton were transferred:

(millions of Canadian dollars)	
Working capital	33
Property, plant and equipment and intangibles (net)	360
Other long-term assets	6
Long-term liabilities	(205)

As a result of the spin-off, goodwill related to Hydro One Brampton of $60 million was eliminated from the Consolidated Balance Sheet.

Acquisition of Haldimand Hydro

On June 30, 2015, Hydro One acquired 100% of the common shares of Haldimand Hydro, an electricity distribution company located in southwestern Ontario. The final total purchase price for Haldimand Hydro was approximately $73 million.

The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Cash and cash equivalents	3
Working capital	5
Property, plant and equipment	52
Deferred income tax assets	1
Goodwill	33
Long-term debt	(18)
Regulatory liabilities	(3)
	73

The determination of the fair value of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed.

Goodwill of approximately $33 million arising from the Haldimand Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Haldimand Hydro. All of the goodwill was assigned to Hydro One's Distribution Business segment. Haldimand Hydro contributed revenues of $32 million and net income of $6 million to the Company's consolidated financial results for the year ended December 31, 2015. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Haldimand Hydro's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2015 and therefore, has not been disclosed on a pro forma basis.

Acquisition of Norfolk Power

On August 29, 2014, Hydro One acquired 100% of the common shares of Norfolk Power an electricity distribution and telecom company located in southwestern Ontario. Norfolk Power was a holding company for two subsidiaries, Norfolk Power Distribution Inc. (NPDI) and Norfolk Energy Inc. The total purchase price for Norfolk Power, net of the long-term debt assumed, was approximately $68 million. The purchase price was finalized in 2015, with no adjustments to the preliminary purchase price allocation as disclosed at December 31, 2014.

The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Working capital	6
Property, plant and equipment	56
Deferred income tax assets	1
Goodwill	40
Bank indebtedness	(3)
Derivative instruments	(3)
Long-term debt	(26)
Post-retirement and post-employment benefit liability	(1)
Environmental liability	(1)
Long-term accounts payable and other liabilities	(1)
	68

The determination of the fair values of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed.

Goodwill of approximately $40 million arising from the Norfolk Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Norfolk Power. All of the goodwill was assigned to Hydro One's Distribution Business segment. Norfolk Power contributed revenues of $18 million and net income of less than $1 million to the Company's consolidated financial results for the year ended December 31, 2014. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Norfolk Power's financial information was not material to the Company's consolidated financial results for the year ended December 31, 2014 and therefore, has not been disclosed on a pro forma basis.

5. Depreciation And Amortization

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Depreciation of property, plant and equipment	595	565
Amortization of intangible assets	54	53
Asset removal costs	91	81
Amortization of regulatory assets	19	23
	759	722

6. Financing Charges

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Interest on long-term debt	417	432
Other	16	12
Less: Interest capitalized on construction and development in progress	(52)	(49)
Gain on interest-rate swap agreements	(2)	(10)
Interest earned on investments	(3)	(6)
	376	379

7. Income Taxes

Income taxes / 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)*	2015	2014
Income taxes / provision for PILs at statutory rate	217	222
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(37)	(72)
Pension contributions in excess of pension expense	(25)	(24)
Overheads capitalized for accounting but deducted for tax purposes	(15)	(15)
Interest capitalized for accounting but deducted for tax purposes	(13)	(13)
Environmental expenditures	(5)	(5)
Non-refundable investment tax credits	(2)	(3)
Post-retirement and post-employment benefit expense in excess of cash payments	(1)	3
Prior year's adjustments	(1)	(4)
Other	(2)	(1)
Net temporary differences	(101)	(134)
Net tax benefit resulting from transition from PILs Regime to Federal Tax Regime	(19)	–
Hydro One Brampton spin-off	7	–
Net permanent differences	1	1
Total income taxes / provision for PILs	105	89

The major components of income tax expense are as follows:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Current income taxes / provision for PILs	2,949	79
Deferred income taxes / provision for (recovery of) PILs	(2,844)	10
Total income taxes / provision for PILs	105	89
Effective income tax rate	12.84%	10.63%

The provision for PILs / current income taxes is remitted to, or received from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime). At December 31, 2015, $12 million (2014 – $39 million) due from the OEFC was included in due from related parties and $1 million (2014 – $nil) due from the CRA was included in prepaid expenses and other assets on the Consolidated Balance Sheet.

In connection with the IPO, Hydro One's exemption from tax under the Federal Tax Regime ceased to apply. Under the PILs Regime, Hydro One was deemed to have disposed of its assets immediately before it lost its tax exempt status under the Federal Tax Regime, resulting in Hydro One making payments in lieu of tax (Departure Tax) totalling $2.6 billion. To enable Hydro One to make the Departure Tax payment, the Province subscribed for common shares of Hydro One for $2.6 billion (See Note 18 – Share Capital). Hydro One used the proceeds of this share subscription to pay the Departure Tax.

At December 31, 2015, the total income taxes / provision for PILs includes deferred income taxes / recovery of PILs of $2,844 million (2014 – deferred provision of $10 million), including $2,810 million (2014 – $nil) resulting from transition from the PILs Regime to the Federal Tax Regime, that is not included in the rate-setting process, using the liability method of accounting. Deferred income taxes / 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 basis of the Company's assets and liabilities. At December 31, 2015 and 2014, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of Canadian dollars)*	2015	2014
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	937	(4)
Post-retirement and post-employment benefits expense in excess of cash payments	578	8
Environmental expenditures	75	4
Non-capital losses	62	–
Other	3	(1)
Total deferred income tax assets	1,655	7
Less: current portion	19	–
	1,636	7

December 31 *(millions of Canadian dollars)*	2015	2014
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	(153)	(140)
Partnership interest	(41)	(38)
Goodwill	(10)	(21)
Capital cost allowance in excess of depreciation and amortization	(1)	(1,713)
Post-retirement and post-employment benefits expense in excess of cash payments	–	559
Environmental expenditures	–	59
Other	(2)	–
Total deferred income tax liabilities	(207)	(1,294)
Less: current portion	–	19
	(207)	(1,313)

During 2015 and 2014, there were no changes in the rate applicable to future taxes. The Company has recorded a valuation allowance in the amount of $278 million (2014 – $nil) in respect of non-depreciable capital property.

8. Accounts Receivable

December 31 *(millions of Canadian dollars)*	2015	2014
Accounts receivable – billed	379	496
Accounts receivable – unbilled	458	586
Accounts receivable, gross	837	1,082
Allowance for doubtful accounts	(61)	(66)
Accounts receivable, net	776	1,016

In 2015, the Company revised the method to estimate the unbilled accounts receivable by using new technology that improved the estimation process. This change has been accounted for on a prospective basis in the consolidated financial statements at December 31, 2015. At December 31, 2015, the change in estimation technology resulted in a reduction in unbilled accounts receivable of approximately $121 million, with a corresponding offset to various components of the retail settlement variance accounts (RSVA). The change in estimate had no significant impact on 2015 net income.

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2015 and 2014:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Allowance for doubtful accounts – January 1	(66)	(36)
Write-offs	37	24
Additions to allowance for doubtful accounts	(32)	(54)
Allowance for doubtful accounts – December 31	(61)	(66)

9. Property, Plant And Equipment

December 31, 2015 *(millions of Canadian dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	13,803	4,625	853	10,031
Distribution	9,205	3,177	238	6,266
Communication	1,165	704	28	489
Administration and service	1,531	848	36	719
Easements	523	60	–	463
	26,227	9,414	1,155	17,968

December 31, 2014 *(millions of Canadian dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	13,209	4,416	626	9,419
Distribution	9,076	3,225	320	6,171
Communication	1,100	615	56	541
Administration and service	1,502	793	23	732
Easements	623	85	–	538
	25,510	9,134	1,025	17,401

Financing charges capitalized on property, plant and equipment under construction were $50 million in 2015 (2014 – $48 million).

10. Intangible Assets

December 31, 2015 *(millions of Canadian dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	579	270	24	333
Other	7	4	–	3
	586	274	24	336

December 31, 2014 *(millions of Canadian dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	573	303	3	273
Other	5	2	–	3
	578	305	3	276

Financing charges capitalized to intangible assets under development were $1 million in 2015 (2014 – $1 million). The estimated annual amortization expense for intangible assets is as follows: 2016 – $57 million; 2017 – $57 million; 2018 – $57 million; 2019 – $47 million; and 2020 – $30 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)*	2015	2014
Regulatory assets:		
Deferred income tax regulatory asset	1,445	1,327
Pension benefit regulatory asset	952	1,236
Post-retirement and post-employment benefits	240	273
Environmental	207	239
RSVA	110	11
Pension cost variance	37	90
2015-2017 rate rider	20	–
DSC exemption	10	16
Share-based compensation	10	–
B2M LP start-up costs	8	–
OEB cost assessment differential	–	12
Other	12	27
Total regulatory assets	3,051	3,231
Less: current portion	36	31
	3,015	3,200
Regulatory liabilities:		
External revenue variance	87	54
Green Energy expenditure variance	76	83
CDM deferral variance	53	25
Deferred income tax regulatory liability	23	21
PST savings deferral	4	19
Other	12	13
Total regulatory liabilities	255	215
Less: current portion	19	47
	236	168

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 income. 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 income tax expense 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 2015 income tax expense would have been higher by approximately $101 million (2014 – $132 million).

Pension Benefit Regulatory Asset

In accordance with OEB 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). 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, 2015 OCI would have been higher by $284 million (2014 – lower by $391 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, 2015 OCI would have been higher by $33 million (2014 – $35 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 2015, the environmental regulatory asset decreased by $24 million (2014 – $33 million) to reflect related changes in the Company's PCB liability, and increased by $1 million (2014 – $13 million) due to changes in the land assessment and remediation 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, 2015 operation, maintenance and administration expenses would have been lower by $23 million (2014 – $20 million). In addition, 2015 amortization expense would have been lower by $19 million (2014 – $18 million), and 2015 financing charges would have been higher by $10 million (2014 – $11 million).

RSVA

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In March 2015, the OEB approved the disposition of the total RSVA balance accumulated from January 2012 to December 2013, including accrued interest, to be recovered through the 2015-2017 Rate Rider. In 2015, the Company revised its method to estimate the unbilled accounts receivable based on new technology implemented to improve the accuracy of the estimation process. At December 31, 2015, the change in estimate reduced unbilled accounts receivable by approximately $121 million, with a corresponding offset to various components of RSVA. The change in estimate had no significant impact on 2015 net income.

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 expenses 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 March 2015, the OEB approved the disposition of the distribution business portion of the total pension cost variance account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In the absence of rate-regulated accounting, 2015 revenue would have been lower by $6 million (2014 – $10 million).

2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' Distribution rate application for 2015-2019 the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account includes the balances approved for disposition by the OEB and will be disposed over a 32-month period in accordance with the OEB decision.

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 identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Network distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account, and there were no additions to this regulatory account in 2015.

Share-based Compensation

The Company recognizes costs associated with stock-based compensation in a regulatory asset as management considers it probable that stock-based compensation costs will be recovered in the future through the rate-setting process. At December 31, 2015 the stock-based compensation costs relate to the share grant plans, are measured at fair value estimated based on grant date share price and recognized using the graded-vesting attribution method. In the absence of rate-regulated accounting 2015 operation, maintenance and administration expenses would have been higher by $5 million (2014 – $nil).

B2M LP Start-up Costs

In December 2015, OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of $8 million of start-up costs relating to B2M LP. The costs will be recovered over a 4 year period beginning in 2016, in accordance with the OEB decision.

OEB Cost Assessment Differential

In April 2010, the OEB issued its Decision regarding Hydro One Networks' distribution 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. In March 2015, the OEB approved the disposition of the OEB Cost Assessment Differential Account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account, and there were no additions to this regulatory account in 2015.

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.

Green Energy Expenditure Variance

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.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. At December 31, 2014, the balance in the CDM deferral variance account relates to the actual 2013 CDM compared to the amounts included in 2013 revenue requirement. At December 31, 2015, the balance also includes the difference between the actual 2014 CDM compared to the amounts included in 2014 revenue requirement. The OEB rate order specifically states that the IESO (Ontario Power Authority (OPA) prior to January 1, 2015) data used to calculate the difference between forecasted and actual savings will be provided one year in arrears, and as a result, no amount should be recorded in advance of notification from the IESO of actual results.

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 administration 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, 2015 and recorded in a deferral account, as directed by the OEB. In March 2015, the OEB approved the disposition of the PST Savings Deferral account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider.

12. Debt And Credit Agreements

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion. At December 31, 2015, Hydro One Inc. had $1,491 million in commercial paper borrowings outstanding (December 31, 2014 – $nil).

At December 31, 2015, Hydro One's consolidated committed, unsecured and unused credit facilities totalling $2,550 million consisted of the following:

(millions of Canadian dollars)	Maturity	Amount
Hydro One Inc.		
Revolving standby credit facility	June 2020	1,500
Three-year senior, revolving term credit facility	October 2018	800
Hydro One		
Five-year senior, revolving term credit facility	November 2020	250
Total		2,550

The Company may use the credit facilities for working capital and general corporate purposes. If used, interest on the credit facilities would apply based on Canadian benchmark rates. The obligation of each lender to make any credit extension 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

At December 31, 2015, all of the Company's long-term debt was issued by Hydro One Inc. under Hydro One Inc.'s Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable by Hydro One Inc. under this program is $3.5 billion. At December 31, 2015, $3.5 billion remained available for issuance until January 2018.

The following table presents Hydro One Inc.'s outstanding long-term debt at December 31, 2015 and 2014:

December 31 (millions of Canadian dollars)	2015	2014
2.95% Series 21 notes due 2015[1]	–	500
Floating-rate Series 22 notes due 2015[2]	–	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	750
Floating-rate Series 31 notes due 2019[2]	228	228
4.40% Series 20 notes due 2020	300	300
1.62% Series 33 notes due 2020[1]	350	–
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	435
4.17% Series 32 notes due 2044	350	350
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
4.29% Series 30 notes due 2064	50	50
	8,723	8,923
Add: Unrealized mark-to-market loss[1]	1	2
Less: Long-term debt payable within one year	(500)	(552)
Long-term debt	8,224	8,373

[1] The unrealized mark-to-market loss relates to $50 million of the Series 33 notes due 2020 (2014 – $250 million of the Series 21 notes due 2015). The unrealized mark-to-market loss is offset by a $1 million (2014 – $2 million) unrealized mark-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 2015, Hydro One Inc. issued $350 million (2014 – $628 million) of long-term debt under the MTN Program, and repaid $550 million of long-term debt MTN Program notes (2014 – $750 million).

Long-term debt totalling $35 million assumed by Hydro One Inc. as part of the Haldimand Hydro and Woodstock Hydro acquisitions was repaid in 2015.

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, 2015 and 2014, the Company's carrying amounts of accounts receivable, due from related parties, cash and cash equivalents, bank indebtedness, short-term notes payable, 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, 2015 and 2014 are as follows:

December 31 *(millions of Canadian dollars)*	2015 Carrying Value	2015 Fair Value	2014 Carrying Value	2014 Fair Value
Long-term debt				
$250 million of MTN Series 21 notes[1]	–	–	252	252
$50 million of MTN Series 33 notes[1]	51	51	–	–
Other notes and debentures[2]	8,673	9,942	8,673	10,159
	8,724	9,993	8,925	10,411

1 The fair value of the $50 million MTN Series 33 notes and $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).

2 The fair value of other notes and debentures, and the portion of 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, 2015, Hydro One Inc. had an interest-rate swap in the amount of $50 million (2014 – $250 million) that was used to convert fixed-rate debt to floating-rate debt. This swap is classified as a fair value hedge. Hydro One Inc.'s fair value hedge exposure was equal to about 1% (2014 – 3%) of its total long-term debt of $8,724 million (2014 – $8,925 million). At December 31, 2015, Hydro One Inc.'s interest-rate swap designated as a fair value hedge was as follows:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt.

At December 31, 2015, the Company had no interest-rate swaps classified as undesignated contracts (2014 – $409 million).

As part of the Norfolk Power and Woodstock Hydro acquisitions, Hydro One Inc. assumed liabilities associated with unrealized losses on derivative instruments (interest-rate swaps) totalling $6 million. Hydro One Inc. extinguished the interest rate swaps and repaid these liabilities in 2015.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2015 and 2014 is as follows:

December 31, 2015 *(millions of Canadian dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	94	94	94	–	–
Derivative instruments					
Fair value hedge – interest-rate swap	1	1	1	–	–
	95	95	95	–	–
Liabilities:					
Short-term notes payable	1,491	1,491	1,491	–	–
Long-term debt	8,724	9,993	–	9,993	–
	10,215	11,484	1,491	9,993	–

December 31, 2014 *(millions of Canadian dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	100	100	100	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	–	2	–
	102	102	100	2	–
Liabilities:					
Bank indebtedness	2	2	2	–	–
Derivative instruments					
Undesignated contracts – interest-rate swaps	3	3	–	3	–
Long-term debt	8,925	10,411	–	10,411	–
	8,930	10,416	2	10,414	–

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

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, 2015 and 2014.

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 costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The OEB-approved adjustment formula for calculating return on equity in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark rates of return for Government of Canada debt. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining its rate of return would reduce the Company's transmission business' 2015 net income by approximately $20 million (2014 – $20 million) and its distribution business' 2015 net income by approximately $13 million (2014 – $10 million). The Company's net income is adversely impacted by rising interest rates as the Company's maturing long-term debt is refinanced at market rates. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

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.

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 net income for the years ended December 31, 2015 or 2014.

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, 2015 and 2014 are included in financing charges as follows:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Unrealized loss (gain) on hedged debt	(1)	(3)
Unrealized loss (gain) on fair value interest-rate swaps	1	3
Net unrealized loss (gain)	–	–

At December 31, 2015, Hydro One had $50 million (2014 – $250 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $1 million (2014 – $2 million). During the years ended December 31, 2015 and 2014, 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, 2015 and 2014, 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, 2015 and 2014, there was no significant accounts receivable balance due from any single customer.

At December 31, 2015, the Company's provision for bad debts was $61 million (2014 – $66 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2015, approximately 6% (2014 – 6%) of the Company's net accounts receivable were aged more than 60 days.

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 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, 2015, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $1 million (2014 – $3 million). At December 31, 2015, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with one financial institution as the counterparty.

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, and the revolving standby facilities totaling $2,550 million. The short-term liquidity under the Commercial Paper Program, and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2015, accounts payable and accrued liabilities in the amount of $753 million (2014 – $784 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2015, Hydro One Inc. had long-term debt in the principal amount of $8,723 million (2014 – $8,923 million). Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of Canadian dollars)*	Weighted Average Interest Rate *(%)*
1 year	500	4.3
2 years	600	5.2
3 years	750	2.8
4 years	228	1.2
5 years	650	2.9
	2,728	3.5
6 – 10 years	600	3.2
Over 10 years	5,395	5.4
	8,723	4.7

Interest payments on long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of Canadian dollars)*
2016	397
2017	386
2018	355
2019	332
2020	322
	1,792
2021-2025	1,496
2026 +	4,080
	7,368

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 access to capital, the Company targets to maintain strong credit quality. The Company considers its capital structure to consist of shareholders' equity, including preferred shares, long-term debt, short-term notes payable, and cash and cash equivalents. At December 31, 2015 and 2014, the Company's capital structure was as follows:

December 31 *(millions of Canadian dollars)*	2015	2014
Long-term debt payable within one year	500	552
Short-term notes payable	1,491	–
Less: cash and cash equivalents	94	100
	1,897	452
Long-term debt	8,224	8,373
Preferred shares	418	323
Common shares	5,623	3,314
Retained earnings	3,806	4,249
	9,429	7,563
Total capital	19,968	16,711

Hydro One Inc. has customary covenants typically associated with long-term debt. Among other things, Hydro One Inc.'s long-term debt and credit facility covenants limit the permissible debt to 75% of its total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2015 and 2014, Hydro One Inc. 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 employees of Haldimand Hydro and Woodstock Hydro. Employees of Haldimand Hydro and Woodstock Hydro participate in the OMERS Plan. 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 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, 2015 were $2 million (2014 – $2 million). At December 31, 2015, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2014 – less than $1 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS Plan, as indicated in OMERS' most recently available annual report for the year ended December 31, 2014.

At December 31, 2014, the OMERS Plan was 90.8% funded, with an unfunded liability of $7.1 billion. This unfunded liability could 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 2015 of $177 million (2014 – $174 million) were based on an actuarial valuation effective December 31, 2013 and the expected level of pensionable earnings. Estimated annual Pension Plan contributions for 2016 are approximately $180 million, based on the actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

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.

Year ended December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of Canadian dollars)	**2015**	2014	**2015**	2014
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**7,535**	6,576	**1,582**	1,531
Current service cost	**186**	145	**43**	41
Interest cost	**302**	312	**64**	73
Benefits paid	**(334)**	(319)	**(47)**	(45)
Net actuarial loss (gain)	**(6)**	821	**(27)**	(18)
Change due to Hydro One Brampton spin-off	**–**	–	**(5)**	–
Projected benefit obligation, end of year	**7,683**	7,535	**1,610**	1,582
Change in plan assets				
Fair value of plan assets, beginning of year	**6,299**	5,731	**–**	–
Actual return on plan assets	**582**	703	**–**	–
Benefits paid	**(334)**	(319)	**–**	–
Employer contributions	**177**	174	**–**	–
Employee contributions	**40**	35	**–**	–
Administrative expenses	**(33)**	(25)	**–**	–
Fair value of plan assets, end of year	**6,731**	6,299	**–**	–
Unfunded status	**952**	1,236	**1,610**	1,582

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

December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of Canadian dollars)	**2015**	2014	**2015**	2014
Accrued liabilities	**–**	–	**50**	49
Pension benefit liability	**952**	1,236	**–**	–
Post-retirement and post-employment benefit liability	**–**	–	**1,560**	1,533
Unfunded status	**952**	1,236	**1,610**	1,582

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)*	2015	2014
PBO	7,683	7,535
ABO	7,020	6,887
Fair value of plan assets	6,731	6,299

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2015 (2014 – 91%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2015 (2014 – 84%). 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, 2015 and 2014 for the Pension Plan:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Current service cost, net of employee contributions	146	110
Interest cost	302	312
Expected return on plan assets, net of expenses	(406)	(369)
Actuarial loss amortization	119	103
Prior service cost amortization	2	2
Net periodic benefit costs	163	158
Charged to results of operations[1]	81	81

[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, 2015, pension costs of $177 million (2014 – $174 million) were attributed to labour, of which $81 million (2014 – $81 million) was charged to operations, and $96 million (2014 – $93 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, 2015 and 2014 for the post-retirement and post-employment benefit plans:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Current service cost, net of employee contributions	43	41
Interest cost	64	73
Actuarial loss amortization	14	18
Prior service cost amortization	–	2
Net periodic benefit costs	121	134
Charged to results of operations	55	62

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 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, 2015 and 2014:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2015**	2014	**2015**	2014
Significant assumptions:				
Weighted average discount rate	**4.00%**	4.00%	**4.10%**	4.00%
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]	**–**	–	**4.36%**	4.36%

[1] 6.38% per annum in 2016, grading down to 4.36% per annum in and after 2031 (2014 – 6.52% in 2015, grading down to 4.36% 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, 2015 and 2014. 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	**2015**	2014
Pension Benefits:		
Weighted average expected rate of return on plan assets	**6.50%**	6.50%
Weighted average discount rate	**4.00%**	4.75%
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)*	**13**	11
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	**4.00%**	4.75%
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)*	**13.8**	12
Rate of increase in health care cost trends[1]	**4.36%**	4.39%

[1] 6.52% per annum in 2015, grading down to 4.36% per annum in and after 2031 (2014 – 6.81% in 2014, grading down to 4.39% 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 a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2015 and 2014 is as follows:

December 31 *(millions of Canadian dollars)*	**2015**	2014
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	**252**	248
Effect of a 1% decrease in health care cost trends	**(196)**	(193)

The effect of a 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, 2015 and 2014 is as follows:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	2014
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	**22**	23
Effect of a 1% decrease in health care cost trends	**(16)**	(17)

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, 2015 and 2014:

December 31, 2015 Life expectancy at 65 for a member currently at				December 31, 2014 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**	23	25	24	26

Estimated Future Benefit Payments

At December 31, 2015, estimated future benefit payments to the participants of the Plans were:

(millions of Canadian dollars)	**Pension Benefits**	Post-Retirement and Post-Employment Benefits
2016	316	53
2017	328	55
2018	339	57
2019	350	59
2020	360	61
2021 through to 2025	1,928	342
Total estimated future benefit payments through to 2025	3,621	627

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)*	2015	2014
Pension Benefits:		
Actuarial loss (gain) for the year	(181)	511
Actuarial loss amortization	(119)	(103)
Prior service cost amortization	(2)	(2)
	(302)	406
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	(27)	(18)
Actuarial loss amortization	(14)	(18)
Prior service cost amortization	–	(2)
	(41)	(38)

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, 2015 and 2014:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Pension Benefits:		
Prior service cost	–	2
Actuarial loss	952	1,234
	952	1,236
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	240	273
	240	273

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:

December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of Canadian dollars)	2015	2014	2015	2014
Prior service cost	–	2	–	–
Actuarial loss	96	119	8	10
	96	121	8	10

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension 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 Human Resource 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, 2015, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55.0	58.2
Debt securities	35.0	36.4
Other[1]	10.0	5.4
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2015, the Pension Plan held $9 million Hydro One corporate bonds (2014 – $nil) and $420 million of debt securities of the Province (2014 – $340 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, 2015 and 2014. 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, 2015 and 2014, 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 & Poor's Rating Services, DBRS Limited, and Fitch Ratings Inc., and "A1" by Moody's Investors Service, 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, 2015 and 2014:

December 31, 2015 *(millions of Canadian dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	–	23	299	322
Cash and cash equivalents	191	–	–	191
Short-term securities	–	80	–	80
Real estate	–	–	2	2
Corporate shares – Canadian	923	–	–	923
Corporate shares – Foreign	2,931	–	–	2,931
Bonds and debentures – Canadian	–	2,074	–	2,074
Bonds and debentures – Foreign	–	199	–	199
Total fair value of plan assets[1]	4,045	2,376	301	6,722

[1] At December 31, 2015, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, and $18 million relating to accruals for pension administration expense and foreign exchange contracts payable.

December 31, 2014 *(millions of Canadian dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	–	18	142	160
Cash and cash equivalents	166	–	–	166
Short-term securities	–	176	–	176
Real estate	–	–	2	2
Corporate shares – Canadian	1,008	–	–	1,008
Corporate shares – Foreign	2,766	–	–	2,766
Bonds and debentures – Canadian	–	1,799	–	1,799
Bonds and debentures – Foreign	–	211	–	211
Total fair value of plan assets[1]	3,940	2,204	144	6,288

[1] At December 31, 2014, the total fair value of Pension Plan assets excludes $18 million of interest and dividends receivable, and $7 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, 2015 and 2014. 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)	2015	2014
Fair value, beginning of year	144	119
Realized and unrealized gains	51	30
Purchases	106	23
Sales and disbursements	–	(28)
Fair value, end of year	301	144

There were no significant transfers between any of the fair value levels during the years ended December 31, 2015 and 2014.

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, real estate and infrastructure 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. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity, real estate and infrastructure 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 and infrastructure 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 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, 2015 and 2014:

Year ended December 31, 2015 *(millions of Canadian dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities, January 1	172	67	239
Interest accretion	8	2	10
Expenditures	(8)	(11)	(19)
Revaluation adjustment	(24)	1	(23)
Environmental liabilities, December 31	148	59	207
Less: current portion	12	10	22
	136	49	185

Year ended December 31, 2014 *(millions of Canadian dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities, January 1	201	65	266
Interest accretion	9	2	11
Expenditures	(5)	(13)	(18)
Revaluation adjustment	(33)	13	(20)
Environmental liabilities, December 31	172	67	239
Less: current portion	8	10	18
	164	57	221

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, 2015 *(millions of Canadian dollars)*	**PCB**	**Land Assessment and Remediation**	**Total**
Undiscounted environmental liabilities	**168**	**61**	**229**
Less: discounting accumulated liabilities to present value	**20**	**2**	**22**
Discounted environmental liabilities	**148**	**59**	**207**

December 31, 2014 *(millions of Canadian dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	195	70	265
Less: discounting accumulated liabilities to present value	23	3	26
Discounted environmental liabilities	172	67	239

At December 31, 2015, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2016	22
2017	25
2018	26
2019	28
2020	30
Thereafter	98
	229

Hydro One records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment 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.

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 2.0% 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.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act,* 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. 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 $168 million (2014 – $195 million). These expenditures are expected to be incurred over the period from 2016 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2015 to reduce the PCB environmental liability by $24 million (2014 – $33 million).

Land Assessment and Remediation

The Company's best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $61 million (2014 –$70 million). These expenditures are expected to be incurred over the period from 2016 to 2023. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2015 to increase the land assessment and remediation environmental liability by $1 million (2014 – $13 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. Asset retirement obligations, 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 asset retirement obligation 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 asset retirement obligation, 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 asset retirement obligations, 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 asset retirement obligations 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. Asset retirement obligations 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, 2015, Hydro One had recorded asset retirement obligations of $9 million (2014 – $9 million), consisting of $8 million (2014 – $8 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 $1 million (2014 – $1 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal.

18. Share Capital

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2015, the Company had 595,000,000 common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2015, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At December 31, 2015, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Holders of Hydro One's preferred shares are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares, and are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares, with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One.

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares are entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board of Directors, payable quarterly. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One on November 20, 2020 and on November 20 of every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 of every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion. At December 31, 2015, Series 1 preferred dividends of $3 million or $0.18 per share were in arrears.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One at a redemption price equal to $25.00 for each Series 2 preferred share redeemed, if redeemed on November 20, 2025 or on November 20 of every fifth year thereafter, or $25.50 for each Series 2 preferred share redeemed, if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 of every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

Prior to October 31, 2015, the Company had 12,920,000 issued and outstanding 5.5% cumulative preferred shares held by the Province, with a redemption value of $25 per share or $323 million total value. These preferred shares were entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which was payable on a quarterly basis. These preferred shares had conditions for their redemption that were outside the control of the Company because the Province could exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. At December 31, 2014, these preferred shares were classified on the Consolidated Balance Sheet as temporary equity because the redemption feature was outside the control of the Company. On October 31, 2015, these preferred shares were purchased and cancelled by Hydro One Inc. See "Reorganization" below for further details.

Reorganization

Prior to the completion of the IPO, Hydro One and Hydro One Inc. completed a series of transactions (Pre-IPO Transactions) that resulted in, among other things, on October 31, 2015, Hydro One acquiring all of the issued and outstanding shares of Hydro One Inc. from the Province and issuing new common shares and preferred shares to the Province.

The following tables present the changes to common and preferred shares as a result of Pre-IPO Transactions, as well as the movement in the number of common and preferred shares during the year ended December 31, 2015. There was no movement in common or preferred shares during the year ended December 31, 2014.

		Preferred Shares	
(millions of Canadian dollars)	Common Shares	Equity	Temporary Equity
Common shares issued – purchase and cancellation of preferred shares *(c)*	323	–	(323)
Acquisition of Hydro One Inc. *(d)*			
Common shares of Hydro One Inc. acquired by Hydro One	(3,441)	–	–
Common shares of Hydro One issued to Province	3,023	–	–
Preferred shares of Hydro One issued to Province	–	418	–
Common shares issued *(e)*	2,600	–	–
Total Pre-IPO Transactions adjustment	2,505	418	(323)

		Preferred Shares	
(number of shares)	Common Shares	Equity	Temporary Equity
Number of shares – January 1, 2015 *(a)*	100,000	–	12,920,000
Common shares issued *(b)*	100,000	–	–
Pre-IPO Transactions:			
Common shares issued – purchase and cancellation of preferred shares *(c)*	2,640	–	(12,920,000)
Acquisition of Hydro One Inc.*(d)*			
Common shares of Hydro One Inc. acquired by Hydro One	(102,640)	–	–
Common shares of Hydro One issued to Province	12,197,500,000	–	–
Preferred shares of Hydro One issued to Province	–	16,720,000	–
Common shares issued *(e)*	2,600,000,000	–	–
Common shares consolidation *(f)*	(14,202,600,000)	–	–
Number of shares – December 31, 2015	595,000,000	16,720,000	–

(a) At January 1, 2015, all common and preferred shares represent the shares of Hydro One Inc.

(b) On August 31, 2015, Hydro One was incorporated under the *Business Corporations Act* (Ontario) and issued 100,000 common shares to the Province for proceeds of $100,000.

(c) On October 31, 2015, Hydro One Inc. purchased and cancelled 12,920,000 preferred shares of Hydro One Inc. previously held by the Province for cancellation at a price equal to the redemption price of the preferred shares totaling $323 million, which was satisfied by the issuance to the Province of 2,640 common shares of Hydro One Inc.

(d) On October 31, 2015, all of the issued and outstanding common shares of Hydro One Inc. were acquired by Hydro One from the Province in return for 12,197,500,000 common shares of Hydro One and 16,720,000 Series 1 preferred shares of Hydro One.

(e) On November 4, 2015, Hydro One issued 2.6 billion common shares to the Province for proceeds of $2.6 billion.

(f) On November 4, 2015, the common shares of Hydro One were consolidated by way of articles of amendment approved by the Province as sole shareholder so that, after such consolidation, 595,000,000 common shares of Hydro One were issued and outstanding.

Share Ownership Restrictions

The *Electricity Act* imposes share ownership restrictions on securities of Hydro One carrying a voting right (Voting Securities). These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (Share Ownership Restrictions). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

19. Dividends

In 2015, preferred share dividends in the amount of $13 million (2014 – $18 million) and common share dividends in the amount of $875 million (2014 – $269 million) were declared.

In August 2015, Hydro One declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton. See Note 4 – Business Combinations.

20. Earnings Per Share

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding.

Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding adjusted for the effects of potentially dilutive share grant plans, which is calculated using the treasury stock method.

Year ended December 31	2015	2014
Net income attributable to common shareholders *(millions of Canadian dollars)*	690	731
Weighted average number of shares		
Basic	496,272,733	477,837,100
Effect of dilutive share grant plans *(Note 21)*	94,691	–
Diluted	496,367,424	477,837,100
EPS		
Basic	$1.39	$1.53
Diluted	$1.39	$1.53

Pro forma Adjusted non-GAAP Basic and Diluted EPS

The following pro forma adjusted non-GAAP basic and diluted EPS has been prepared by management on a supplementary basis which assumes that the total number of common shares outstanding was 595,000,000 in each of the years ended December 31, 2015 and 2014. The supplementary pro forma disclosure is used internally by management subsequent to the IPO of Hydro One to assess the Company's performance and is considered useful because it eliminates the impact of the issuance of common shares to the Province prior to the IPO. Prior to the IPO, the Province was the sole shareholder of Hydro One and disclosure of EPS did not provide meaningful information. EPS is considered an important measure and management believes that presenting it for all periods based on the number of outstanding shares on, and subsequent to, the IPO provides users with a basis to evaluate the operations of the Company with comparable companies.

Year ended December 31 *(unaudited)*	2015	2014
Net income attributable to common shareholders *(millions of Canadian dollars)*	690	731
Pro forma weighted average number of common shares		
Basic	595,000,000	595,000,000
Effect of dilutive share grant plans *(Note 21)*	94,691	–
Diluted	595,094,691	595,000,000
Pro forma adjusted non-GAAP EPS		
Basic	$1.16	$1.23
Diluted	$1.16	$1.23

The above pro forma adjusted non-GAAP basic and diluted EPS does not have any standardized meaning in US GAAP.

21. Stock-based Compensation

Share Grant Plans

At December 31, 2015, Hydro One had two share grant plans, one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the Power Workers' Union annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU share grant plan begins on July 3, 2015, which is the date the share grant plans were ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,979,062 common shares were granted under the PWU Share Grant Plan.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of The Society of Energy Professionals annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan begins on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,433,292 common shares were granted under the Society Share Grant Plan.

The fair value of the share grants is estimated based on the grant date share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. Total fair value of shares granted in 2015 is $111 million (2014 – $nil). Total share based compensation recognized during 2015 was $10 million (2014 – $nil) and was recorded as a regulatory asset. The historical turnover rate relating to members of the Power Workers' Union and The Society of Energy Professionals is not believed to be reflective of a future turnover rate due to benefits conferred by the share grant plans. At December 31, 2015 the Company expects all eligible employees to receive the share grants until such time that they no longer meet the eligibility criteria and therefore, a forfeiture rate of 0% is assumed in amounts recognized during 2015. The Company will reevaluate this assumption in subsequent periods based on actual experience.

A summary of share grant activity under the Plan as of December 31, 2015 is presented below:

Years ended December 31, 2015	Share Grants *(Number)*	Weighted-Average Price
Outstanding – beginning of year	–	–
Granted (non-vested)	5,412,354	$20.50
Outstanding – end of year	5,412,354	–

Directors' DSU Plan

Under the Company's Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

(number of DSUs)	2015	2014
DSUs outstanding – January 1	–	–
DSUs granted	20,525	–
DSUs outstanding – December 31	20,525	–

For the year ended December 31, 2015, an expense of less than $1 million (2014 – $nil) was recognized in earnings with respect to the DSU Plan. At December 31, 2015, a liability of less than $1 million (December 31, 2014 – $nil), related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.29 and is included in accrued liabilities on the Balance Sheet.

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company will match 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. No contributions were made under the ESOP during 2015.

Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One adopted a Long-term Incentive Plan (LTIP). Under the LTIP, long-term incentives will be granted to certain executive and management employees, and all equity-based awards will be settled in newly-issued shares of Hydro One from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares.

The LTIP provides flexibility to award a range of vehicles, including restricted share units, performance share units, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance. No long-term incentives were awarded during 2015.

22. Noncontrolling Interest

On December 16, 2014, the relevant Bruce to Milton Line transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation (SON) acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's initial investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), Hydro One purchase the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in noncontrolling interest for the years ended December 31, 2015 and December 31, 2014:

Year ended December 31, 2015 *(millions of Canadian dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – January 1, 2015	21	49	70
Distributions to noncontrolling interest	(1)	(4)	(5)
Net income attributable to noncontrolling interest	3	7	10
Noncontrolling interest – December 31, 2015	23	52	75

Year ended December 31, 2014 *(millions of Canadian dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – January 1, 2014	–	–	–
Amount contributed by noncontrolling interest	22	50	72
Net income (loss) attributable to noncontrolling interest	(1)	(1)	(2)
Noncontrolling interest – December 31, 2014	21	49	70

23. Related Party Transactions

The Province is the majority shareholder of Hydro One. The OEFC, IESO, Ontario Power Generation Inc. (OPG), the OEB, and Hydro One Brampton are related parties to Hydro One because they are controlled or significantly influenced by the Province. Effective January 1, 2015, the OPA and IESO have merged and are now operating as IESO.

The Province

- During 2015, Hydro One paid dividends to the Province totalling $888 million (2014 – $287 million). In addition, on August 31, 2015, Hydro One declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton. See Note 4 – Business Combinations.
- On November 4, 2015, Hydro One issued common shares to the Province for proceeds of $2.6 billion. See Note 18 – Share Capital.
- During 2015, Hydro One Inc. incurred certain IPO related expenses totaling $7 million, which will be reimbursed to the Company by the Province.

IESO

- In 2015, Hydro One purchased power in the amount of $2,318 million (2014 – $2,601 million) from the IESO-administered electricity market.
- Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues for 2015 include $1,548 million (2014 – $1,556 million) related to these services.
- Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues for 2015 include $127 million (2014 – $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 for 2015 include $32 million (2014 – $32 million) related to these services.
- The IESO (OPA prior to January 1, 2015) funds substantially all of the Company's CDM programs. The funding includes program costs, incentives, and management fees. During 2015, Hydro One received $70 million (2014 – $33 million) related to these programs.

OPG

- In 2015, Hydro One purchased power in the amount of $11 million (2014 – $23 million) from OPG.
- Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2015, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $7 million (2014 – $12 million), primarily for the Transmission Business. Operation, maintenance and administration costs in 2015 and 2014 related to the purchase of services with respect to these service level agreements were not significant.

OEFC

- In 2015, Hydro One made PILs to the OEFC totalling $2.9 billion (2014 – $86 million), including Departure Tax of $2.6 billion (2014 – $nil).
- In 2015, Hydro One purchased power in the amount of $6 million (2014 – $9 million) from power contracts administered by the OEFC.
- During 2015, Hydro One paid a $8 million (2014 – $5 million) 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. Hydro One has not made any claims under the indemnity since it was put in place in 1999. Hydro One and the OEFC, with the consent of the Minister of Finance, terminated the indemnity fee effective October 31, 2015.
- PILs and payments in lieu of property taxes were paid to the OEFC.

OEB

- 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 2015, Hydro One incurred $12 million (2014 – $12 million) in OEB fees.

Hydro One Brampton

- Effective August 31, 2015, Hydro One Brampton is no longer a subsidiary of Hydro One, but is indirectly owned by the Province. For change in ownership of Hydro One Brampton, see Note 4 – Business Combinations.
- Subsequent to August 31, 2015, Hydro One continues to provide certain management, administrative and smart meter network services to Hydro One Brampton pursuant to certain service level agreements, which are provided at market rates. These agreements will continue until the end of 2016 (except in the case of smart meter network services, which will continue until the end of 2017). Hydro One Brampton has the right to renew these agreements (other than smart meter network services) for additional one-year terms to end no later than December 31, 2019. Additionally, on August 31, 2015, Hydro One Inc. and Hydro One Brampton entered into a license agreement which permits Hydro One Brampton to use the "Hydro One" name and related licensed marks. These agreements will terminate if the Province disposes of its interest in Hydro One Brampton, except in the case of the smart meter network services agreement, which is anticipated to continue for a transition period after the Province disposes of its interest in Hydro One Brampton. During 2015, revenues related to the provision of services with respect to these service level agreements were $1 million.

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.

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

(millions of Canadian dollars)	December 31, 2015	December 31, 2014
Due from related parties	191	224
Due to related parties[1]	(138)	(227)

[1] Included in due to related parties at December 31, 2015 are amounts owing to the IESO in respect of power purchases of $134 million (2014 – $214 million).

24. 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)*	2015	2014
Accounts receivable	240	(93)
Due from related parties	33	(27)
Materials and supplies	2	–
Prepaid expenses and other assets	4	(13)
Accounts payable	(23)	39
Accrued liabilities	(15)	(35)
Due to related parties	(89)	(3)
Accrued interest	(4)	–
Long-term accounts payable and other liabilities	–	(3)
Post-retirement and post-employment benefit liability	60	80
	208	(55)

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 accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	2014
Capital investments in property, plant and equipment	**(1,623)**	(1,511)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	**28**	30
Capital expenditures – property, plant and equipment	**(1,595)**	(1,481)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	2014
Capital investments in intangible assets	**(40)**	(19)
Net change in accruals included in capital investments in intangible assets	**3**	(4)
Capital expenditures – intangible assets	**(37)**	(23)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2015, capital contributions from these reassessments totalled $62 million, which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments. No reassessments occurred in 2014.

Supplementary Information

Year ended December 31 *(millions of Canadian dollars)*	**2015**	2014
Net interest paid	**416**	412
Income taxes / PILs paid	**2,933**	86

25. 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.

In September 2015, Hydro One and three of its subsidiaries were served with a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. Hydro One intends to defend the action. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

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 2015, the Company paid approximately $1 million (2014 – $1 million) in respect of consents obtained. 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.

26. Commitments

Outsourcing Agreements

Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., provides services to Hydro One, including settlements, source to pay services, pay operations services, information technology, finance and accounting services. The agreement with Inergi for these services expires in December 2019. In addition, Inergi provides customer service operations outsourcing services to Hydro One. The agreement for these services expires in February 2018.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The current agreement with Brookfield expires in December 2024.

At December 31, 2015, the annual commitments under the outsourcing agreements were as follows: 2016 – $167 million; 2017 – $138 million; 2018 – $106 million; 2019 – $99 million; 2020 – $2 million; and thereafter – $11 million.

Trilliant Agreement

In December 2015, Hydro One entered into an agreement with Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (Trilliant) for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licenses, as well as certain professional services. This agreement is for a term of ten years, from December 31, 2015 to December 31, 2025, with the option to renew for an additional term of five years at Hydro One's sole discretion. At December 31, 2015, the annual commitments under the agreement were as follows: 2016 – $17 million; 2017 – $17 million; 2018 – $17 million; 2019 – $17 million; 2020 – $16 million; and thereafter – $6 million.

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, 2015, Hydro One Inc. provided prudential support to the IESO on behalf of its subsidiaries using parental guarantees of $329 million (2014 – $330 million), and on behalf of a distributor using guarantees of $1 million (2014 – $1 million). In addition, as at December 31, 2015, Hydro One Inc. has provided letters of credit in the amount of $15 million (2014 – $8 million) to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributor 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 Hydro One Inc.'s liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One Inc. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One Inc. 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 Hydro One Inc.'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, 2015, Hydro One Inc. had letters of credit of $139 million (2014 – $126 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 typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. 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 or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases.

During the year ended December 31, 2015, the Company made lease payments totaling $7 million (2014 – $11 million). At December 31, 2015, the future minimum lease payments under non-cancellable operating leases were as follows; 2016 –$11 million; 2017 – $10 million; 2018 – $9 million; 2019 – $4 million; 2020 – $8 million; and thereafter – $3 million.

27. Segmented Reporting

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of transmitting high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering electricity to end customers and certain other municipal electricity distributors; and
- Other Business, which includes certain corporate activities and the operations of the Company's 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 income taxes 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, 2015 *(millions of Canadian dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,536	4,949	53	6,538
Purchased power	–	3,450	–	3,450
Operation, maintenance and administration	426	633	76	1,135
Depreciation and amortization	374	380	5	759
Income (loss) before financing charges and income taxes	736	486	(28)	1,194
Capital investments	943	711	9	1,663

Year ended December 31, 2014 *(millions of Canadian dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,588	4,903	57	6,548
Purchased power	–	3,419	–	3,419
Operation, maintenance and administration	394	742	56	1,192
Depreciation and amortization	346	367	9	722
Income (loss) before financing charges and income taxes	848	375	(8)	1,215
Capital investments	845	680	5	1,530

Total Assets by Segment:

December 31 *(millions of Canadian dollars)*	2015	2014
Transmission	12,066	12,540
Distribution	9,213	9,805
Other	3,049	205
Total assets	24,328	22,550

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

28. Subsequent Events

Dividends

On February 11, 2016, preferred share dividends in the amount of $6 million and common share dividends in the amount of $202 million were declared.

Dividend Reinvestment Plan

On February 11, 2016, Hydro One's Board of Directors approved the creation of a Dividend Reinvestment Plan which the Company currently intends to put in place in March 2016. The Dividend Reinvestment Plan will enable eligible shareholders to have their regular quarterly cash dividends automatically reinvested in additional Hydro One common shares acquired on the open market.

Great Lakes Power Transmission Purchase Agreement

On January 28, 2016, Hydro One reached an agreement to acquire from Brookfield Infrastructure various entities that own and control Great Lakes Power Transmission LP, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario, for $222 million in cash, subject to customary adjustments, plus the assumption of approximately $151 million in outstanding indebtedness. The acquisition is pending a *Competition Act* approval as well as regulatory approval from the OEB.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Address
483 Bay Street
Toronto, ON M5G 2P5
tel: 416-345-5000 or 1-877-955-1155
www.HydroOne.com

Customer Inquiries
Hydro One Networks Inc.
P.O. Box 5700
Markham, ON L3R 1C8

Billing and Service Inquiries:
tel: 1-888-664-9376
fax: 1-888-625-4401 or 905-944-3251
e-mail: CustomerCommunications@HydroOne.com

Report an Emergency (24 hours):
tel: 1-800-434-1235

General Shareholder Inquiries
Computershare Trust Company of Canada
100 University Avenue
Toronto, ON M5J 2Y1
tel: 514-982-7555 or 1-800-564-6253
fax: 1-888-453-0330 or 416-263-9394
e-mail: service@computershare.com

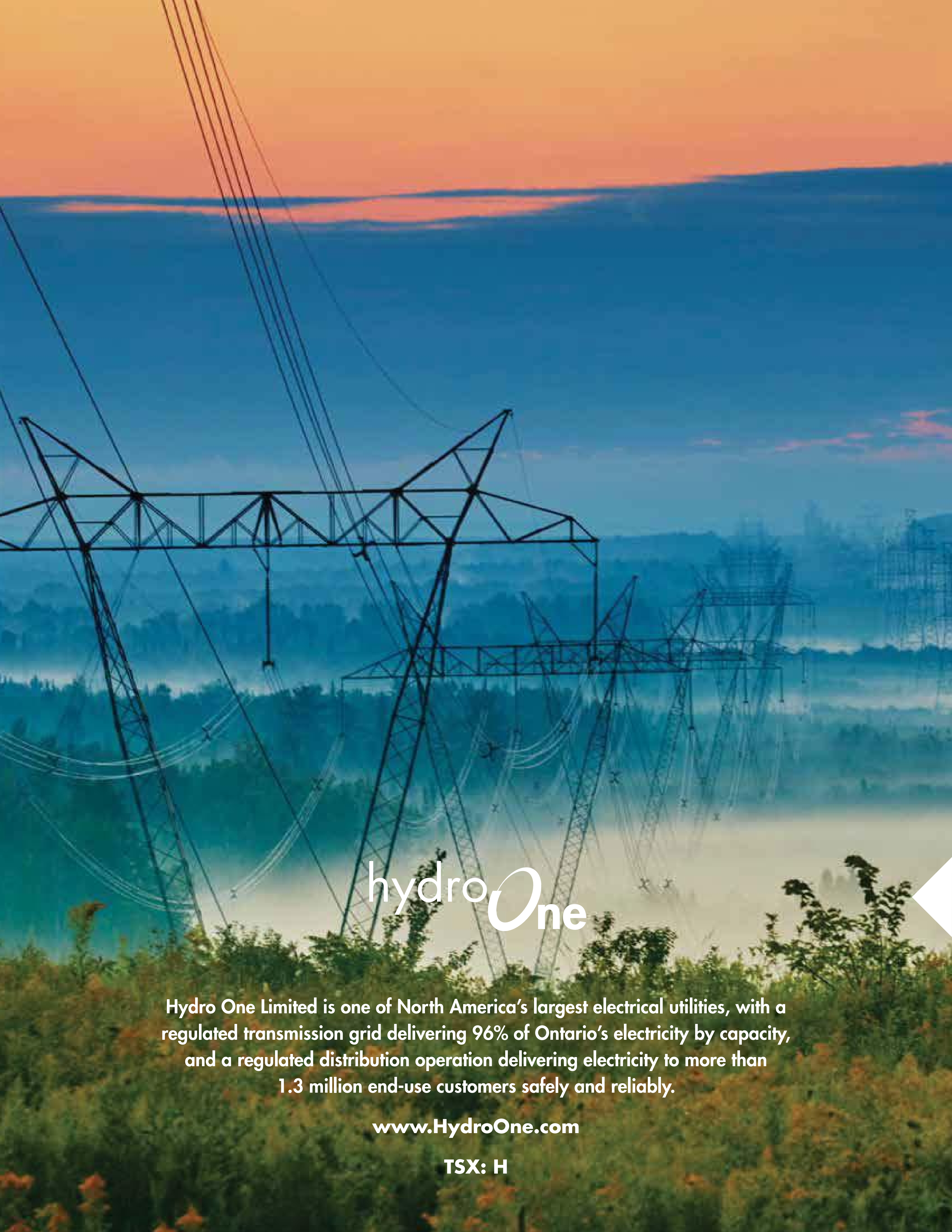
Dividend Reinvestment Plan (DRIP)
tel: 514-982-7555 or 1-800-564-6253
www.HydroOne.com/DRIP

Institutional Investors and Securities Analysts
tel: 416-345-6867
e-mail: investor.relations@HydroOne.com

Media Inquiries
tel: 416-345-6868 or 1-877-506-7584

Dividends
Unless indicated otherwise, all dividends paid by Hydro One Limited to common shareholders are designated as “eligible” dividends for the purpose of the Income Tax Act (Canada) and any similar provincial legislation.

H LISTED ON TMX Toronto Stock Exchange



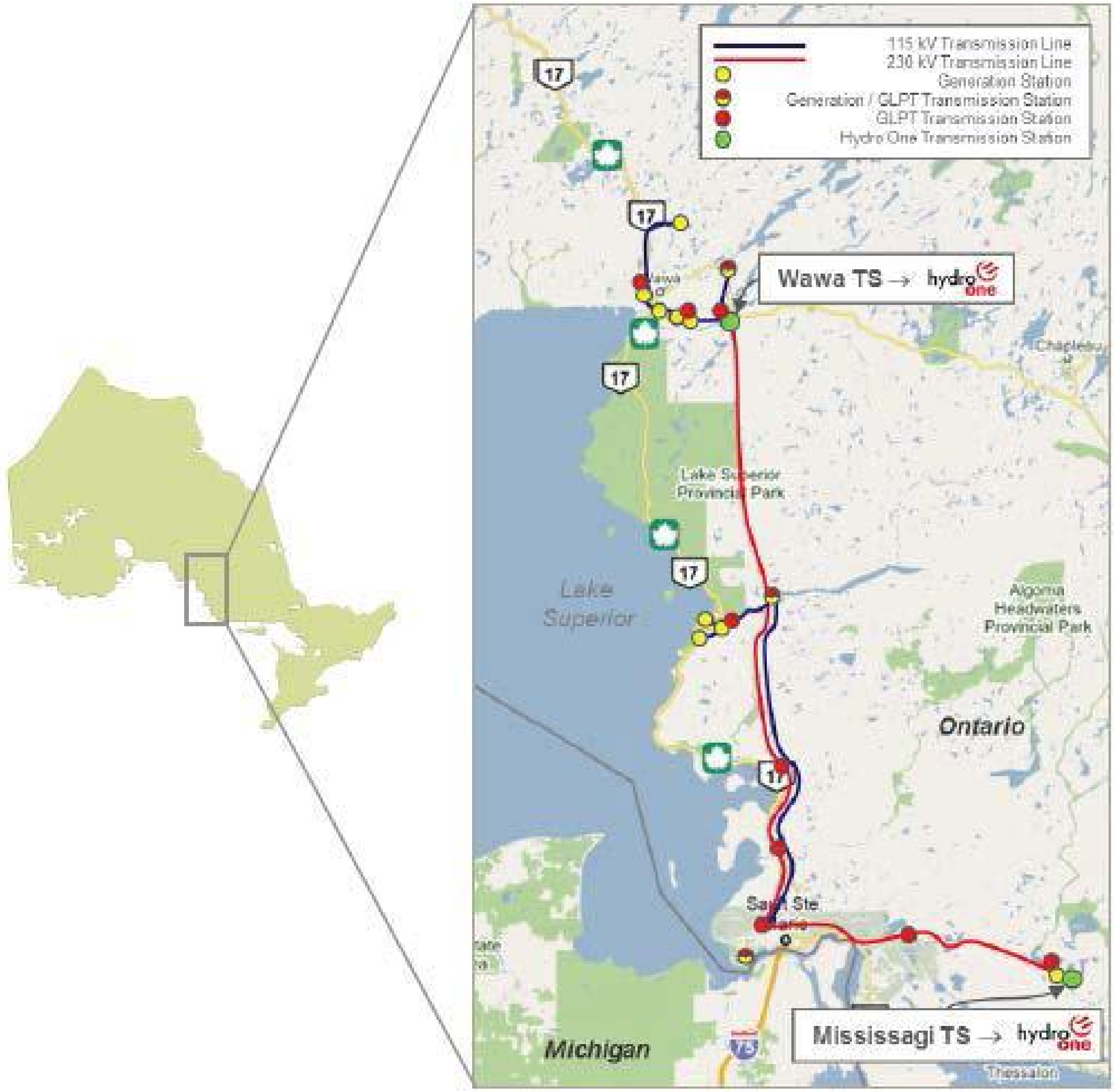
hydroOne

Hydro One Limited is one of North America's largest electrical utilities, with a regulated transmission grid delivering 96% of Ontario's electricity by capacity, and a regulated distribution operation delivering electricity to more than 1.3 million end-use customers safely and reliably.

www.HydroOne.com

TSX: H

GLPT's Transmission System



Financial Statements

GREAT LAKES POWER TRANSMISSION LIMITED PARTNERSHIP

December 31, 2013

Deloitte.

Deloitte LLP
Brookfield Place
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Toronto ON M5J 2V1
Canada

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Independent Auditor's Report

To the Partners of
Great Lakes Power Transmission Limited Partnership

We have audited the accompanying financial statements of Great Lakes Power Transmission Limited Partnership, which comprise the statements of financial position as at December 31, 2013, December 31, 2012 and January 1, 2012, and the statements of income and comprehensive income (loss), statements of changes in partners' equity and statements of cash flows for the years ended December 31, 2013 and December 31, 2012, 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 International Financial Reporting Standards, 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.

Auditor's Responsibility

Our responsibility is to express an opinion on these 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 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 auditor's 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, 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 financial statements present fairly, in all material respects, the financial position of Great Lakes Power Transmission Limited Partnership as at December 31, 2013, December 31, 2012 and January 1, 2012 and its financial performance and its cash flows for the years ended December 31, 2013 and December 31, 2012 in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
April 25, 2014

Great Lakes Power Transmission Limited Partnership

Statement of Financial Position

Expressed in thousands of Canadian dollars

	Note	**December 31, 2013**	December 31, 2012 (note 22)	January 1, 2012 (note 22)
Assets				
Current Assets				
Cash		**$ 5,593**	$ 182	$ 219
Trade and other receivables		**,476**	3,057	2,980
Due from related parties	*21*	**36**	1,667	1,041
Prepaid expenses and other		**370**	806	559
		9,475	5,712	4,799
Property, plant and equipment, net	*5*	**225,085**	230,209	225,800
Intangible assets, net	*6*	**3,162**	3,707	3,928
		$ 237,722	$ 239,628	$ 234,527
Liabilities				
Current Liabilities				
Trade and other payables	*7*	**$ 2,973**	$ 2,881	$ 3,786
Due to related parties	*21*	**585**	397	195
Current portion of Trans senior bonds	*9*	**2,043**	973	-
		5,601	4,251	3,981
Pension liability	*8*	**7,052**	8,958	5,674
Trans senior bonds	*9*	**114,719**	116,542	117,341
		127,372	129,751	126,996
Partners' equity		**110,350**	109,877	107,531
		$ 237,722	$ 239,628	$ 234,527

Great Lakes Power Transmission Limited Partnership

Statement of Changes in Partners' Equity

Expressed in thousands of Canadian dollars

	Note	Capital: Great Lakes Power Transmission Holdings LP	Capital: Great Lakes Power Transmission Inc.	Accumulated other comprehensive income (loss)	Retained earnings (deficit)	Total partners' equity
Balance at January 1, 2013	*1*	$ 112,405	$ 11	$ (3,516)	$ 977	$ 109,877
Net income		-	-	-	11,178	11,178
Distributions paid		-	-	-	(12,923)	(12,923)
Other comprehensive income		-	-	2,218	-	2,218
Balance at December 31, 2013		$ 112,405	$ 11	$ (1,298)	$ (768)	$ 110,350

	Note	Capital: Great Lakes Power Transmission Holdings LP	Capital: Great Lakes Power Transmission Inc.	Accumulated other comprehensive income (loss)	Retained earnings (Deficit)	Total partners' equity
Balance at January 1, 2012	*1, 22*	$ 107,905	$ 11	$ -	$ (385)	$ 107,531
Net income		-	-	-	13,362	13,362
Distributions paid		-	-	-	(12,000)	(12,000)
Capital contributions	*1*	4,500	-	-	-	4,500
Other comprehensive loss		-	-	(3,516)	-	(3,516)
Balance at December 31, 2012		$ 112,405	$ 11	$ (3,516)	$ 977	$ 109,877

Great Lakes Power Transmission Limited Partnership

Statement of Income and Other Comprehensive Income (Loss)

Expressed in thousands of Canadian dollars

Years ended December 31,	Note		2013		2012
					(note 22)
Revenue		$	**39,640**	$	36,821
Operating expenses					
Operating and administration	*12*		**8,858**		7,934
Depreciation and amortization	*15*		**9,284**		8,600
Maintenance	*13*		**1,861**		1,681
Taxes, other than income taxes			**107**		108
			20,109		18,323
Net operating income			**19,531**		18,498
Finance income			**(47)**		(27)
Finance costs	*14*		**7,947**		6,785
Other income	*17*		**-**		(2,461)
Loss on disposal of property, plant and equipment and intangible assets	*5, 6*		**453**		839
Income for the year			**11,178**		13,362
Other comprehensive income (loss)					
Remeasurement of pension liability	*8*		**2,218**		(3,516)
Total comprehensive income		$	**13,396**	$	9,846

Great Lakes Power Transmission Limited Partnership
Statement of Cash Flows
Expressed in thousands of Canadian dollars

Years ended December 31,	*Note*		**2013**		2012
Operating Activities					
Net income		**$**	**11,178**	$	13,362
Items not affecting cash;					
Depreciation and amortization	*15*		**9,284**		8,600
Finance cost	*14*		**7,947**		6,785
Loss on disposal of property, plant and equipment and intangible assets	*5, 6*		**453**		839
Net change in non-cash working capital and other	*18*		**2,681**		(486)
Operating Cash flows before interest			**31,543**		29,100
Cash interest paid			**(7,920)**		(7,920)
			23,623		21,180
Investing Activities					
Proceeds on disposition of property, plant and equipment	*5*		**18**		24
Additions to property, plant and equipment and intangible assets			**(4,334)**		(13,742)
			(4,316)		(13,718)
Financing Activities					
Distributions paid			**(12,923)**		(12,000)
Principal repayments			**(973)**		-
Capital contributions			**-**		4,500
			(13,896)		(7,500)
(Decrease) increase in cash			**5,411**		(37)
Cash, beginning balance			**182**		219
Cash, ending balance		**$**	**5,593**	$	182

1. GENERAL INFORMATION

Ontario-based Great Lakes Power Transmission Limited Partnership (the "Partnership") was formed on May 17, 2007 for the purpose of acquiring the assets and liabilities of the transmission division of Great Lakes Power Limited ("GLPL"), a related party due to common ownership. The address of the Partnership's registered office is 2 Sackville Road, Suite B, Sault Ste. Marie, Ontario, Canada, P6B 6J6.

Effective March 26, 2013, the shareholders of the Partnership entered into a series of transactions which resulted in the Limited Partner, Brookfield Infrastructure Holdings (Canada) Inc. ("BIH") transferring its 20,285,007 Class A Units of the Partnership to newly formed Great Lakes Power Transmission Holdings LP in exchange for 145,984,400 Class A Units of Great Lakes Power Transmission Holdings LP. There was no change in the General Partner.

Great Lakes Power Transmission Holdings LP is the Limited Partner and holds a 99.99% interest in the Partnership. Great Lakes Power Transmission Inc., the General Partner, holds a 0.01% limited interest in the Partnership and is responsible for management of the Partnership. Both the General and Limited Partners are wholly owned subsidiaries of Brookfield Infrastructure Partners LP ("BIP"), the ultimate parent company and controlling party of the group.

The Partnership is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board ("OEB").

2. BASIS OF PRESENTATION

Statement of compliance

These financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). These are the Partnership's first financial statements prepared in accordance with IFRS and IFRS 1, *First-time Adoption of International Financial Reporting Standards* has been applied. The financial statements were approved and authorized for issue by those charged with governance of the Partnership on April 25, 2014.

The Partnership's annual financial statements, formerly prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), differs from IFRS in certain respects. In preparing the IFRS statements, the Partnership amended certain accounting and valuation methods that had been applied under Canadian GAAP, as explained in Note 22. The accounting policies presented in Note 3 have been applied in preparing the financial statements for the year ended December 31, 2013, the comparative financial statements for the year ended December 31, 2012 and the opening IFRS balance sheet as of January 1, 2012. In the transition from Canadian GAAP to IFRS, the Partnership followed the provisions of IFRS 1.

The Partnership's effective date of transition to IFRS was January 1, 2012 ("Transition Date"). Reconciliations and descriptions of the effect of transition from Canadian GAAP to IFRS on the Partnership's financial statements are provided in Note 22.

2. BASIS OF PRESENTATION (continued)

Basis of measurement

The financial statements have been prepared on a going concern assumption using the historical cost basis except where otherwise noted. Historical cost is generally based on the fair value of the consideration given in exchange for assets or settlement of liabilities as at the date the transaction occurs.

Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Partnership's functional currency. All amounts have been rounded to the nearest thousand, unless otherwise indicated.

Critical judgments and estimation uncertainties

In the preparation of these financial statements in conformity with IFRS, management makes judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of revenues, expenses, assets and liabilities. Facts and circumstances may change and actual results could differ from those estimates.

Estimates

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Information about critical judgments and estimates in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements are included in the following notes:

Impairment

Assets, including property, plant and equipment and intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. The assessment of the fair value often requires estimates and assumptions such as discount rates, commodity prices, rehabilitation and restoration costs, future capital requirements and future operating performance. Changes in such estimates could impact recoverable values of these assets. Estimates are reviewed regularly by management.

Depreciation of property, plant and equipment

Each property, plant and equipment and intangible asset, which is assessed annually, is assessed for both its physical life limitations and its economic recoverability. Those assets with a finite life are depreciated on a straight-line basis and for these, management estimates the useful life of the assets. These assessments require the use of estimates and assumptions including market conditions at the end of the assets useful life. Asset useful lives and residual values are re-evaluated annually.

Environmental rehabilitation

Significant estimates and assumptions are made in determining the environmental rehabilitation costs as there are numerous factors that will affect the ultimate liability payable. These factors

2. BASIS OF PRESENTATION (continued)

include estimates of the extent and costs of rehabilitation activities, technological changes, regulatory changes, cost increases and changes in discount rates, which may result in future actual expenditure differing from the amounts currently provided.

Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these assets cannot be reasonably estimated and therefore, the fair value of the associated environmental rehabilitation costs cannot be determined at this time. As a result, no environmental rehabilitation costs have been accrued in these financial statements.

Fair value disclosures of Trans senior bonds

The Partnership has estimated the fair value for disclosure purposes of the its Trans senior bonds as they are not separately traded, and are determined based on future cash flows and the timing of settlement and assumptions about discount rate, credit risk and by incorporating other assumptions made by market participants.

Pension

Significant estimates and assumptions are made in determining pension and employee future benefits as there are numerous factors that will affect the pension obligation. The actuarial determination of the accrued benefit obligation for pensions and post-employment benefits uses the projected unit credit method prorated on service which incorporates management's best estimate of future salary levels, other cost escalation, mortality rates, retirement ages of employees and other actuarial factors. In addition, actuarial determinations used in estimating obligations relating to the defined benefit plans incorporate assumptions using management's best estimates of factors including plan performance, salary escalation, retirement dates of employees and drug cost escalation rates.

Judgments

Impairment

Judgment is involved in assessing whether there is any indication that an asset or cash generating unit may be impaired. This assessment is made based on the analysis of, amongst other factors, changes in the market or business environment, events that have transpired that have impacted the asset or cash generating unit.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Partnership has consistently applied the following accounting policies to all periods presented in these financial statements:

(a) *Financial instruments*

The Partnership recognizes all financial instruments at fair value upon initial recognition and subsequently classifies them into one of the following categories: financial assets and financial liabilities at fair value through profit or loss, held-to-maturity, loans and receivables, available-for-sale and other liabilities.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(i) Financial assets and financial liabilities – recognition and derecognition

The Partnership initially recognizes loans and receivables issued on the date when they are originated. All other financial assets and financial liabilities are initially recognized on the trade date.

The Partnership derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows in a transaction in which substantially all of the risks and rewards of ownership of the financial asset are transferred, or it neither transfers nor retains substantially all of the risks and rewards of ownership and does not retain control over the transferred asset. Any interest in such derecognized financial assets that is created or retained by the Partnership is recognized as a separate asset or liability.

The Partnership derecognizes a financial liability when its contractual obligations are discharged, cancelled, or expire.

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position when, and only when, the Partnership has a legal right to offset the amounts and intends either to settle them on a net basis or to realize the asset and settle the liability simultaneously.

(ii) Financial assets and financial liabilities – measurement

Financial Assets

(i) Held to maturity and Loans and receivables

These assets are initially recognized at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, they are measured at amortized cost less impairment losses using the effective interest method.

(ii) Financial assets at fair value through profit or loss ("FVTPL")

A financial asset is classified as at fair value through profit or loss if it is classified as held-for-trading or is designated as such on initial recognition. Directly attributable transaction costs are recognized in profit or loss as incurred. Financial assets at fair value through profit or loss are measured at fair value and changes therein are recognized in profit or loss.

(iii) Available-for-sale financial assets ("AFS")

A financial asset is classified as available-for-sale if it is a non-derivative financial asset which is not classified as (a) loans and receivables, (b) held-to-maturity investments or (c) financial assets at fair value through profit or loss. Available-for-sale financial assets are measured at fair value with unrealized gains and losses recognized in other comprehensive income. All transactions costs are included in the carrying value of the financial instrument.

The fair value of financial assets traded in active markets (FVTPL and AFS) is based on quoted market prices at the date of the statements of financial position.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial Liabilities

(iv) Other liabilities

Other liabilities are non-derivative financial liabilities that are not designated as at fair value through profit or loss. These financial liabilities are initially measured at fair value net of transaction costs, subsequently measured at amortized cost using the effective interest method.

(b) *Impairment*

(i) Financial assets

Financial assets, other than those classified as at fair value through profit and loss, are reviewed at each reporting date to determine whether there is objective evidence of impairment, meaning that the estimated future cash flows have been negatively affected. Objective evidence of impairment could include significant financial difficulty, default or delinquency by a debtor or financial reorganization of a counterparty.

Impairment losses are calculated as follows:

(i) Financial assets carried at amortized cost

The Partnership assesses if there is objective evidence that an impairment loss on loans and receivables or held-to-maturity investments carried at amortized cost has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows (excluding future credit losses that have not been incurred) discounted at the financial asset's original effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account. Losses are recognized directly in profit or loss. If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized, the previously recognized impairment is reversed by adjusting the allowance account. Reversals do not result in a carrying amount of the financial asset that exceeds what the amortized cost would have been had the impairment not been recognized at the date the impairment is reversed. The amounts of the reversals are recognized in profit or loss.

(ii) Available-for-sale financial assets

When the Partnership had recognized a decline in the fair value of an available-for-sale in other comprehensive income and there is objective evidence that the asset is impaired, the cumulative loss that had been recognized in other comprehensive income is reclassified from accumulated other comprehensive income (loss) to profit or loss. The amount of the cumulative loss that is reclassified from equity to profit or loss is the difference between the acquisition cost (net of any principal repayment and amortization) and current fair value, less any impairment loss on that financial asset previously recognized in profit or loss. The impairment losses recognized in profit or loss for an investment in an equity instrument classified as available for sale is not reversed through profit or loss.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(iii) Non-financial assets

At each reporting date, the Partnership reviews the carrying amount of its non-financial assets to determine whether there is any indication of impairment. Impairment assessments are conducted at the level of cash-generating units ("CGU"). A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets. If any such indication exists, the recoverable amount of the CGU is estimated.

The recoverable amount of the CGU is the greater of its value in use and its fair value less costs to sell. Value in use is based on the estimated future cash flows, discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized in profit or loss if the carrying amount of a CGU exceeds its recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If such indications exist, the Partnership estimates the recoverable amount of that CGU. A reversal of an impairment loss is recognized up to the lesser of the recoverable amount or the carrying amount that would have been determined (net of depreciation charges) has no impairment loss been recognized on the CGU.

(c) *Property, plant and equipment*

(i) Recognition and measurement

Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. The cost of major inspections or overhauls is capitalized and costs relating to the replacement of a major part of property, plant and equipment are recognized in the carrying amount of the asset to which that part relates, if it is probable that the inspection, overhaul or replacement part will generate future economic benefits and its cost can be measured reliably. The carrying amount of previous inspections and overhauls, or the part being replaced is derecognized and any gain or loss is recognized in profit or loss. The cost of the day-to-day servicing of property, plant and equipment is recognized in operating and administration and maintenance expense as incurred.

Costs included in the carrying amount of property, plant and equipment include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects are capitalized during the construction period, if those projects meet the definition of a qualifying asset. Major projects (qualifying assets) are those projects that are under construction for a substantial period of time. Capitalization of borrowing costs is suspended during extended periods in which construction development is interrupted. Assets under construction are recorded as in progress until they are available for use.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

When property, plant and equipment is disposed of or retired, the related cost, accumulated depreciation and any accumulated impairment losses are eliminated. Any resulting gains or losses are reflected in profit or loss in the period the asset is disposed of or retired.

(ii) Subsequent expenditure

Subsequent expenditure is capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to the Partnership.

(iii) Depreciation

The cost, net of estimated residual values, of assets classified as property, plant and equipment are amortized over the estimated useful life of the asset using a straight-line method. Land is not depreciated.

The estimated useful lives of property, plant and equipment are as follows:

	Method	Rate
Transmission assets	Straight-line	5 to 60 years
Equipment and other assets	Straight-line	5 to 30 years

The estimated useful lives, residual values and method of depreciation are based on depreciation studies and are reviewed annually for reasonableness.

The costs of construction work in progress are not depreciated until the assets are available for their intended use.

(d) *Intangible assets*

Acquired intangible assets having finite useful lives are measured at cost less accumulated amortization and any accumulated impairment losses. Intangible assets are capitalized if: it is probable that the asset acquired or developed will generate future economic benefits, intangibles are identifiable and the Partnership exerts control over the economic benefit to be derived from the asset. The costs incurred to establish technological feasibility or to maintain existing levels of performance are recognized in operating and maintenance expense as incurred.

The carrying costs of intangible assets include expenditures that are directly attributable to the acquisition or development of the asset. The cost of self-developed assets includes materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects are capitalized during the development period. Major projects (or qualifying assets) are those projects that are under development for a substantial period of time. Assets under development are recorded as in progress until they are available for use.

Subsequent expenditures are capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. All other expenditures are recognized in profit or loss as incurred.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Amortization is based on the cost of the asset less its residual value and is calculated using the straight-line method over the estimated useful life of the asset from the date the asset is available for use, and is generally recognized in profit or loss. The useful lives of intangible assets range from 5 to 15 years. Land rights with indefinite lives are not amortized.

The estimated useful lives, residual values and method of amortization are reviewed annually for reasonableness.

Intangibles with an indefinite life are tested for impairment on an annual basis.

(e) *Leases*

(i) Determination if an arrangement contains a lease

At inception of an arrangement, the Partnership determines whether the arrangement is or contains a lease.

At inception or upon reassessment of an arrangement that contains a lease, the Partnership separates payments and other consideration required by the arrangement into consideration relating to the lease and consideration relating to other elements of an arrangement. This is done on the basis of the relative fair values of the different components of the arrangement. If the Partnership concludes that the arrangement would constitute a finance lease and it is impracticable to separate the payments pertaining to the arrangement reliably, then an asset and a liability are recognized at an amount equal to the fair value of the underlying asset; subsequently, the liability is reduced as payments are made and an imputed finance cost of the liability is recognized using the Partnership's incremental borrowing rate.

(ii) Leased assets

Assets held by the Partnership under leases that transfer to the Partnership substantially all of the risks and rewards of ownership are classified as finance leases. The leased assets are measured initially at an amount equal to the lower of their fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the assets are accounted for in accordance with the accounting policy applicable to that asset. At December 31, 2013, the Partnership did not have arrangements which were classified as finance leases.

Assets held under other leases are classified as operating leases and are not recognized in the Partnership's statement of financial position.

(iii) Lease payments

Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease.

Minimum lease payments made under finance leases are apportioned between the finance expense and the reduction of the outstanding liability. The finance expense is allocated to each period during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) *Employee benefits*

(i) Short-term employee benefits

Short-term employee benefits are expensed as the related service is provided by the employee. A liability is recognized for the amount expected to be paid if the Partnership has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Defined contribution plans

Obligations for contributions to defined contribution plans are expensed as the related service is provided by the employee. Prepaid contributions are recognized as an asset to the extent that a cash refund or a reduction in future payments is available.

(iii) Defined benefit plans

The Partnership's net obligation in respect of defined benefit plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in the current and prior periods, discounting that amount and deducting the fair value of any plan assets.

The calculation of defined benefit obligations is performed annually by a qualified actuary using the projected unit credit method. When the calculation results in a potential asset for the Partnership, the recognized asset is limited to the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. To calculate the present value of economic benefits, consideration is given to any applicable minimum funding requirements.

Remeasurements of the net defined benefit liability, which comprise actuarial gains and losses, the return on plan assets (excluding interest) and the effect of the asset ceiling (if any, excluding interest), are recognized immediately in other comprehensive income. The Partnership determines the net interest expense (income) on the net defined benefit liability (asset) for the period by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the then-net defined benefit liability (asset), taking into account any changes in the net defined benefit liability (asset) during the period as a result of contributions and benefit payments. Net interest expense and other expenses related to defined benefit plans are recognized in profit or loss.

When the benefits of a plan are changed or when a plan is curtailed, the resulting change in benefit that relates to past service or the gain or loss on curtailment is recognized immediately in profit or loss. The Partnership recognizes gains and losses on the settlement of a defined benefit plan when the settlement occurs. The gain or loss on curtailment or settlement comprises any resulting change in the fair value of plan assets, any change in the present value of the defined benefit obligation, any relating actuarial gains or losses and past service costs that had not been previously been recognized.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(iv) Other long-term employee benefits

The Partnership's net obligation in respect of long-term employee benefits is the amount of future benefit that employees have earned in return for their service in the current and prior periods. That benefit is discounted to determine its present value. Remeasurements are recognized in profit or loss in the period in which they arise.

(g) *Revenue*

Revenue is measured at the fair value of the consideration received or receivable. Revenue is recognized by the Partnership when a sales arrangement exists, delivery of goods or services has occurred, the amount of revenue and costs incurred or to be incurred in respect of the transaction can be measured reliably and it is probable that future economic benefits will flow to the Partnership.

The Partnership recognizes revenue on an accrual basis, when electricity is wheeled, at the regulated rate established by the OEB.

(h) *Foreign currency*

Transactions in foreign currencies are translated to the functional currency of the Partnership at exchange rates at the dates of the transactions.

(i) *Borrowing costs*

Borrowing costs that are directly attributable to the acquisition, construction or development of a qualifying asset are added to the cost of that asset, until it is available for use. Qualifying assets are those that take a substantial period of time to get ready for their intended use. The Partnership capitalizes borrowing costs by applying its cost of debt. All other borrowing costs are recognized in finance expense in the period in which they are incurred.

4. FUTURE CHANGES IN ACCOUNTING POLICIES

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning after December 31, 2013 and have not been applied in preparing these financial statements. Those which may be relevant to the Partnership are set out below. The Partnership does not plan to early adopt any of these standards.

IFRS 9 and IAS 32 and IAS 39 Financial Instruments

IFRS 9, Financial instruments ("IFRS 9") was issued by the IASB on November 12, 2009 and will replace the requirements of IAS 39 Financial Instruments: Recognition and Measurement ("IAS 39"). IFRS 9 requires that all financial assets be classified and subsequently measured at amortized cost or at fair value based on the Partnership's business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial liabilities are classified as subsequently measured at amortized cost except for financial liabilities classified as at FVTPL, financial guarantees and certain other exceptions. In November 2013, the IASB issued amendments to IFRS 9 deferring the mandatory effective date until the IFRS 9 project is closer to completion. The Partnership has not yet evaluated the impact the final standard is expected to have on its financial statements.

4. FUTURE CHANGES IN ACCOUNTING POLICIES (continued)

An amendment to IAS 32, Financial Instruments: presentation ("IAS 32") was issued by the IASB in December 2011. The amendment clarifies the meaning of 'currently has a legally enforceable right to set-off'. The amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014. The Partnership does not expect the standard to have a material impact its financial statements.

An amendment to IAS 39, Financial Instruments: Recognition and Measurement ("IAS 39") was issued by the IASB in June 2013. The amendment clarifies that there is no need to discontinue hedge accounting if a hedging derivative is novated, provided certain criteria are met. A novation indicates an event where the original parties to a derivative agree that one or more clearing counterparties replace their original counterparty to become the new counterparty to each of the parties. The amendments to IAS 39 are effective for annual periods beginning on or after January 1, 2014. The Partnership does not expect the standard to have a material impact on its financial statements.

IAS 36 Impairment of Assets

An amendment to IAS 36 ("IAS 36") was issued by the IASB in May 2013. The amendment reduces the circumstances in which the recoverable amount of assets or cash-generating units are required to be disclosed, clarifies the disclosures required, and introduces an explicit requirement to disclose the discount rate used in determining impairment. The amendments to IAS 36 are effective for annual periods beginning on or after January 1, 2014. The Partnership does not expect the standard to have a material impact on its financial statements.

IFRS 14 Regulatory Deferral Accounts

This standard was issued by the IASB in January 2014 and applies to an entity's first annual IFRS financial statements for a period beginning on or after 1 January 2016. IFRS 14 Regulatory Deferral Accounts permits an entity which is a first-time adopter of International Financial Reporting Standards to continue to account, with some limited changes, for 'regulatory deferral account balances' in accordance with its previous GAAP, both on initial adoption of IFRS and in subsequent financial statements. Regulatory deferral account balances, and movements in them, are presented separately in the statement of financial position and statement of profit or loss and other comprehensive income, and specific disclosures are required. The Partnership has elected to transition to IFRS prior to the IFRS 14 pronouncement being available to the Partnership.

IFRIC 21 Levies

In May 2013, IFRS Interpretation Committee ("IFRIC") published IFRIC Interpretation 21, Levies ("IFRIC 21"), effective for annual periods beginning on or after January 1, 2014. IFRIC 21 provides guidance on when to recognize a liability for a levy imposed by a government. IFRIC 21 identifies the obligating event for the recognition of a liability as the activity that triggers the payment of the levy in accordance with the relevant legislation. The Partnership is evaluating the impact of this standard on its financial statements.

(expressed in thousands of Canadian dollars)

5. PROPERTY, PLANT AND EQUIPMENT, NET

	Land	Equipment and other assets	Transmission assets	Work-in-progress	Total
Cost					
Balance, January 1, 2012	$ 236	$ 3,034	$ 202,054	$ 20,476	$ 225,800
Additions	-	-	-	13,380	13,380
Transfers	-	5,077	26,452	(31,529)	-
Disposals	-	-	(922)	-	(922)
Balance, December 31, 2012	$ 236	$ 8,111	$ 227,584	$ 2,327	$ 238,258
Additions	-	-	-	4,071	4,071
Transfers	-	1,354	3,103	(4,457)	-
Disposals	-	(5)	(542)	-	(547)
Balance, December 31, 2013	$ 236	$ 9,460	$ 230,145	$ 1,941	$ 241,782
Accumulated Depreciation					
Balance, January 1, 2012	$ -	$ -	$ -	$ -	$ -
Additions	-	587	7,520	-	8,107
Disposals	-	-	(58)	-	(58)
Balance, December 31, 2012	$ -	$ 587	$ 7,462	$ -	$ 8,049
Additions	-	832	7,894	-	8,726
Disposals	-	(5)	(73)	-	(78)
Balance, December 31, 2013	$ -	$ 1,414	$ 15,283	$ -	$ 16,697
Carrying amounts					
Balance, January 1, 2012	$ 236	$ 3,034	$ 202,054	$ 20,476	$ 225,800
Balance, December 31, 2012	$ 236	$ 7,524	$ 220,123	$ 2,327	$ 230,209
Balance, December 31, 2013	$ 236	$ 8,046	$ 214,862	$ 1,941	$ 225,085

During the year, the Partnership disposed of assets with a total net book value of $469 (2012 - $864) for net proceeds of $18 (2012 - $24). A resultant loss on disposal of property, plant and equipment of $451 (2012 - $839) was recorded to the statement of income and other comprehensive income (loss).

(expressed in thousands of Canadian dollars)

6. INTANGIBLE ASSETS, NET

	Land rights	Computer software	Work-in-progress	Total
Cost				
Balance, January 1, 2012	$ 1,102	$ 2,126	$ 700	$ 3,928
Additions	-	-	272	272
Transfers	-	716	(716)	-
Balance, December 31, 2012	1,102	2,842	256	4,200
Additions	-	-	15	15
Disposals	-	(3)	-	(3)
Balance, December 31, 2013	$ 1,102	$ 2,839	$ 271	$ 4,212
Accumulated Depreciation				
Balance, January 1, 2012	$ -	$ -	$ -	$ -
Additions	-	493	-	493
Balance, December 31, 2012	-	493	-	493
Additions	-	558	-	558
Disposals	-	(1)	-	(1)
Balance, December 31, 2013	$ -	$ 1,050	$ -	$ 1,050
Carrying amounts				
Balance, January 1, 2012	$ 1,102	$ 2,126	$ 700	$ 3,928
Balance, December 31, 2012	$ 1,102	$ 2,349	$ 256	$ 3,707
Balance, December 31, 2013	$ 1,102	$ 1,789	$ 271	$ 3,162

During the year, the Partnership disposed of assets with a total net book value of $2 (2012 - $nil) for net proceeds of $nil (2012 - $nil). A resultant loss on disposal of property, plant and equipment of $2 (2012 - $nil) was recorded to the statement of income and other comprehensive income (loss).

7. TRADE AND OTHER PAYABLES

	Dec 31, 2013	Dec 31, 2012	Jan 1, 2012
Trade payables and accruals	$ 862	$ 1,727	$ 2,942
Payroll liabilities	633	654	519
Accrued interest	322	325	325
Connection deposits	838	44	-
Other payables	318	131	-
	$ 2,973	$ 2,881	$3,786

7. TRADE AND OTHER PAYABLES (continued)

The Partnership retains connection deposits for two power generating entities as reimbursement to the Partnership for costs to be incurred in connecting those power generating entities to the Partnership's power transmission property assets. Any unused connection deposit balance will be refunded to the appropriate power generating entity.

8. PENSION AND EMPLOYEE FUTURE BENEFITS

The Partnership is part of a registered defined benefit, final pay pension plan and other post-employment benefit plan (the "Plans").

The other post-employment benefit plan includes benefits such as health and dental care, and life insurance. The obligation under these plans is determined periodically through the preparation of actuarial valuations. The Partnership contributions for the benefit plans for 2013 was $821 (2012 - $1,146).

The Partnership also participates in a defined contribution pension plan provided to certain employees. The Partnership contributes amounts based on the level of employee contributions for this plan. In 2013, the total employer expense for the Partnership's defined contribution pension plan was $119 (2012 - $120).

The Partnership's pension plan information is provided in the following tables:

(expressed in thousands of Canadian dollars)

8. PENSION AND EMPLOYEE FUTURE BENEFITS (continued)

	December 31, 2013			December 31,2012			January 1,2012		
	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total
Change in the present value of the accrued benefit obligation									
Balance, beginning of year	20,362	5,503	25,865	15,627	3,748	19,375	14,436	3,300	17,736
Current service cost	382	278	660	310	204	514	278	107	385
Interest expense	889	241	1,130	808	226	1,034	832	192	1,024
Benefit payments from plan	(756)	(140)	(896)	(763)	(131)	(894)	(752)	(124)	(876)
Employee contributions	132	-	132	134		134	113		113
Increases (decreases) due to other significant events	11	-	11	1,589		1,589			-
Remeasurements:						-			-
Effect of changes in demographic assumptions	837	423	1,260		400	400	720	273	993
Effect of changes in financial assumptions	(1,507)	(597)	(2,104)	1,132	861	1,993			-
Effect of experience adjustments	65	-	65	1,525	195	1,720			-
Effect of changes in foreign exchange rates	-	-	-			-			-
Balance, end of year	20,415	5,708	26,123	20,362	5,503	25,865	15,627	3,748	19,375
Change in fair value of the plan assets									
Fair value, beginning of year	16,907	-	16,907	13,701		13,701	12,752		12,752
Return on plan assets	1,506	-	1,506	282		282	789		789
Contributions:			-			-			-
Employer	681	140	821	1,015	131	1,146	1,537	124	1,661
Employee	132	-	132	134		134	113		113
Benefit payments from plan	(756)	(140)	(896)	(763)	(131)	(894)	(752)	(124)	(876)
Administrative expenses paid from plan assets	(167)	-	(167)	(100)		(100)			-
Interest income	760	-	760	734		734			-
Increases (decreases) due to other significant events	8	-	8	1,904		1,904	(738)		(738)
Fair value, end of year	19,071	-	19,071	16,907	-	16,907	13,701	-	13,701
Net Defined Benefit (Liability)/Asset									
Accrued benefit obligation	(20,415)	(5,708)	(26,123)	(20,362)	(5,503)	(25,865)	(15,627)	(3,748)	(19,375)
Fair value of plan assets	19,071	-	19,071	16,907	-	16,907	13,701	-	13,701
Net Defined Benefit (Liability)/Asset	(1,344)	(5,708)	(7,052)	(3,455)	(5,503)	(8,958)	(1,926)	(3,748)	(5,674)
Total expense/(income) recognized in profit and loss									
Current service cost	382	278	660	310	204	514			-
Net interest expense	129	244	373	74	226	300			-
Administrative expenses and taxes	100	-	100	100	-	100			-
Total expense (income) recognized in profit and loss	811	522	1,133	484	430	914	-	-	-
Actuarial losses/(gains) recognized in statement of comprehensive income									
Effect of changes in demographic assumptions	837	423	1,260	-	400	400			-
Effect of changes in financial assumptions	(1,507)	(597)	(2,104)	1,132	861	1,993			-
Effect of experience adjustments	65	-	65	1,525	195	1,720			-
Effect of experience adjustments	(1,439)	-	(1,439)	(282)		(282)			-
Total actuarial (gains) losses recognized in statement of comprehensive income	(2,044)	(174)	(2,218)	2,375	1,456	3,831	-	-	-

Effects of changes in assumptions

	Revalued pension obligation	Revalued pension obligation	Total
Discount Rate			
Increase by 100 basis points	16,857	797	17,653
Decrease by 100 basis points	22,995	940	23,935
Inflation Rate			
Increase by 100 basis points	20,166	863	21,030
Decrease by 100 basis points	17,113	863	17,977

Significant Actuarial Assumptions	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Defined Benefit Pension Plan	Non-Pension Benefit Plans
	December 31, 2013		December 31, 2012		January 1,2012	
Weighted-Average actuarial assumptions used:						
Discount rate	4.95%	4.95%	4.45%	4.45%	5.30%	5.30%
Rate of compensation increases	3.00%	3.00%	3.00%	3.00%	3.50%	3.50%
Inflation Rate	2.00%	2.00%	2.00%	2.00%	2.50%	2.50%

Plan Assets by asset class allocation (%)	31-Dec-13	31-Dec-12	1-Jan-12
Fixed Income	28%	37%	0%
Equities	71%	59%	100%
Other	1%	4%	0%
Total	100%	100%	100%

(expressed in thousands of Canadian dollars)

9. TRANS SENIOR BONDS

The Trans Senior Bonds (the "Bonds") have a principal amount of $120,000 and are secured by a charge on the partnership's transmission real property assets, both present and future. On behalf of the Partnership, a company related through common control, BIP, obtained a letter of credit in the amount of $3,960 to cover six months of interest payments on the Bonds.

The fair market value of the Bonds as at December 31, 2013 is $139,821 based on current market prices for debt with similar terms (2012 - $149,567, January 1, 2012 - $145,627). Amortization of deferred financing fees for the year related to the Partnership's Bonds are included in finance costs and totalled $220 (2012 - $175).

The Bonds bear interest at the rate of 6.6% per annum. Semi-annual payments of interest only are due and payable on June and December 16 each year until and including June 16, 2013. Equal blended semi-annual payments of principal and interest on the Bonds commenced on December 16, 2013 and will continue until and including June 16, 2023. The Bonds will not be fully amortized by their maturity date. The remaining principal balance of the Bonds will be fully due on June 16, 2023.

	Dec 31, 2013	Dec 31, 2012	Jan 1, 2012
Trans senior bonds	$ 119,027	$ 120,000	$ 120,000
Less: unamortized deferred financing fees	(2,265)	(2,485)	(2,659)
Less: current portion	(2,043)	(973)	-
	$ 114,719	$ 116,542	$117,341

As at December 31, 2013, principal repayments due in each of the next five years were as follows:

	2014	2015	2016	2017	2018
Principal repayments	$ 2,043	$ 2,180	$ 2,327	$ 2,483	$ 2,649

During the year, the Partnership identified a number of projects which were considered to be qualifying assets for purposes of capitalizing borrowing costs. For the year ended December 31, 2013, the Partnership capitalized borrowing costs of $190 (2012 - $1,310). The capitalization rate on funds borrowed amounted to 6.6% (2012 - 6.6%).

10. PARTNERSHIP UNITS

As described in Note 1, the Partnership's shareholders entered into a series of transactions which resulted in a change to the Limited Partner from being Brookfield Infrastructure Holdings (Canada) Inc. to Great Lakes Power Transmission Holdings LP, both related parties due to common ownership.

The Partnership is authorized to issue an unlimited number of Class A and Class B partnership units, of which 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2013. 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2012.

(expressed in thousands of Canadian dollars)

11. COMMITMENTS AND CONTINGENCIES

(a) Letters of credit

On behalf of the Partnership, BIP obtained a letter of credit totalling $3,960 to cover six months of interest payments on the Bonds. No amount has been drawn against this letter of credit.

(b) Commitments

As at December 31, 2013 future minimum lease payments for operating leases entered into by the Partnership, as lessee, were as follows:

	2014	2015-2018	Thereafter
Minimum lease payments	$417	$1,345	$336

(c) Contingencies

The Partnership may, from time to time, be involved in legal proceedings, claims and litigation that arises in the ordinary course of business which the Partnership believes would not reasonably be expected to have a material adverse effect on the financial condition of the Partnership.

There are no specified decommissioning costs relating to the Ontario transmission assets. The Partnership has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to optimum industry standards. Replacement of the assets occurs in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which the Partnership would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

(expressed in thousands of Canadian dollars)

12. OPERATING AND ADMINISTRATION EXPENSES

	2013	2012
Compensation expenses	$ 5,655	$ 5,672
Contract expenses	1,606	1,470
Materials	532	536
Other	1,065	256
	$ 8,858	$ 7,934

13. MAINTENANCE EXPENSES

	2013	2012
Compensation expenses	$ 430	$ 420
Contract expenses	736	503
Materials	146	42
Other	549	716
	$ 1,861	$ 1,681

14. FINANCE COSTS

	2013	2012
Interest expense on Trans senior bonds	$ 7,917	$ 7,920
Amortization of deferred financing fees on Trans senior bonds	220	175
Less: capitalized interest	(190)	(1,310)
	$ 7,947	$ 6,785

15. DEPRECIATION AND AMORTIZATION

	2013	2012
Depreciation on property, plant and equipment	$ 8,726	$ 8,107
Amortization of intangible assets	558	493
	$ 9,284	$ 8,600

16. INCOME TAXES

The Partnership does not record income tax expenses as it is not subject to income taxation as a result of its formation as a limited partnership.

(expressed in thousands of Canadian dollars)

17. OTHER INCOME

During 2012, the Partnership recovered $2,461 of previously incurred development-related expenses through a related party, Great Lakes Power Transmission EWT LP ("GLPT EWT LP").

18. STATEMENT OF CASH FLOWS

(a) Net change in non-cash working capital related to operations

	2013	2012
Trade and other receivables	$ (419)	$ (78)
Prepaid expenses and other	436	(247)
Due from related parties	1,631	(626)
Trade and other payables	533	495
Due to related parties	188	202
Pension liability	312	(232)
	$ 2,681	$ (486)

19. CAPITAL RISK MANAGEMENT

The Partnership's primary capital management objective is to ensure the sustainability of its capital to support continuing operations, meet its financial obligations, allow for growth opportunities and provide stable distributions to its partners. The Partnership manages its capital to maintain an investment grade credit rating while prudently making use of leverage in order to provide its ultimate parent with enhanced returns. In addition, the Partnership manages its capital to ensure access to incremental borrowings needed to fund new growth initiatives.

The Partnership manages its capital structure in accordance with changes in economic conditions. Generally, capital expenditures are funded with external borrowings. In order to adjust the capital structure, the Partnership may elect to adjust the distribution amount paid to its partners, increase or reduce the equity participation in new and existing operations, adjust the level of capital spending or issue new partnership units.

The Partnership manages its capital in order to maintain a debt to capitalization ratio below 75%. As at December 31, 2013, the ratio was 52% (2012 – 52%, January 1, 2012 - 53%). The table below presents the detail of the Partnership's capitalization and the calculation of the ratio:

	Dec 31, 2013	Dec 31, 2012	Jan 1, 2012
Trans senior bonds	$ 119,027	$ 120,000	$ 120,000
	119,027	120,000	120,000
Partners' equity	110,350	109,877	107,531
Total capitalization	$ 229,377	$ 229,877	$227,531
Debt to capitalization	52%	52%	53%

There has been no change in the Partnership's approach to managing capital in the year.

(expressed in thousands of Canadian dollars)

20. FINANCIAL INSTRUMENTS

(a) Fair value measurement

The Partnership defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The Partnership classifies its financial assets and liabilities as outlined below:

		December 31, 2013		December 31, 2012		January 1, 2012	
	Class	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets							
Cash	LAR	$ 5,593	$ 5,593	$ 182	$ 182	$ 219	$ 219
Trade and other receivables	LAR	3,476	3,476	3,057	3,057	2,980	2,980
Financial liabilities							
Trade and other payables	OL	2,973	2,973	2,881	2,881	3,786	3,786
Trans senior bonds	OL	116,762	139,821	116,542	149,567	117,341	145,627

Classification details:

FVTPL – fair value through profit or loss
LAR – loans and receivables
OL – other liabilities

The statements of financial position carrying amounts for cash, trade and other receivables, prepaid expenses and other assets, trade and other payables, and due to and from related parties approximate fair value due to their short-term nature. Due to the use of subjective judgments and uncertainties in the determination of fair values, these values should not be interpreted as being realizable in an immediate settlement of the financial instruments.

Fair value hierarchy

The following provides a description of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable:

• Level 1 fair value measurements are those derived from quoted market prices (unadjusted) in active markets for identical assets or liabilities;

• Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and

• Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

20. FINANCIAL INSTRUMENTS (continued)

No financial instruments have been ranked level 2 or 3, except for the Bonds which are ranked as level 2.

There were no transfers between Level 1, 2 and 3 during the reporting periods. The fair values of financial assets and liabilities carried at amortized cost are approximated by their carrying values, except for the Bonds whose fair market value is presented in note 9.

(b) Financial risk management

The Partnership has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk.

The Partnership's management has overall responsibility for the establishment and oversight of the Partnership's risk management framework. Risk management policies are established to identify and analyze the risks faced by the Partnership, to set appropriate risk limits and controls and to monitor risks and ensure adherence to these limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Partnership's activities. The Partnership, through its training and management standards and procedures, aims to maintain a disciplined and constructive control environment in which all employees understand their roles and obligations. The objectives, policies and processes for managing risk were consistent with those in the prior year.

(i) Market Risk

Market risk is the risk that changes in market prices (interest rates) will affect the Partnership's income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Partnership's Bonds are subject to a fixed interest rate of 6.6% per annum, payable semi-annually on June 16 and December 16. As a result of having fixed rate debt, fluctuations in market interest rates are not expected to materially affect the Partnership's cash flows.

(ii) Credit Risk

Credit risk is the risk of financial loss to the Partnership if a counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Partnership's receivables from counterparties. The carrying amount of financial assets represents the maximum credit exposure.

The Partnership actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

The majority of trade receivable transactions entered by the Partnership are with the Independent Electricity System Operator ("IESO"). The IESO operates the provincial transmission system, and is a reliable counterparty. The quality of the Partnership's counterparties mitigates the Partnership's exposure to credit risk.

(expressed in thousands of Canadian dollars)

20. FINANCIAL INSTRUMENTS (continued)

The Partnership's maximum exposure to credit risk as at December 31 is as follows:

	December 31, 2013	December 31, 2012	January 1, 2012
Trade and other receivables	$ 3,476	$ 3,057	$ 2,980
	$ 3,476	$3,057	$2,980

The Partnership is also exposed to credit risk on cash. Credit risk is mitigated by ensuring the majority of the financial assets are placed with a major Canadian financial institution with strong investment-grade ratings by a primary ratings agency. The credit risk of cash has been assessed as low.

(iii) Liquidity Risk

Liquidity risk is the risk that the Partnership will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset. The Partnership manages liquidity risk by forecasting cash flows required by operations and anticipating investing and financing activities to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they are due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Partnership's reputation.

The table below analyzes the Partnership's financial liabilities into relevant maturity groupings based on the remaining period at the date of the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows:

		Contractual Maturities				
	Carrying Amount	Less Than 1 Year	1-2 Years	3-5 Years	More Than 5 Years	Total
Trade and other payables	$ 2,973	$ 2,973	$ -	$ -	$ -	$ 2,973
Trans senior bonds	116,762	9,866	9,866	29,598	137,441	186,771
	$119,735	$12,839	$9,866	$29,598	$137,441	$189,744

At year end, the Partnership's relatively stable operating cash flows provide sufficient liquidity to fund these contractual obligations.

21. RELATED PARTY TRANSACTIONS AND BALANCES

Through the normal course of business, the Partnership enters into transactions with parties that meet the definition of a related party. Throughout the year ended December 31, 2013 the Partnership entered into the following transactions with entities considered to be related:

(a) In the normal course of operations, Riskcorp Inc., an insurance broker related through common control, entered into transactions with the Partnership to provide insurance. The total cost allocated to the Partnership in 2013 was $319 (2012 - $267) and no amount remains outstanding at year end.

(b) The Partnership has provided services to and received services from entities under common control in the normal course of operations. The balances payable and receivable for these services are non-interest bearing and unsecured. The balances payable to and receivable from related parties will come due during the following year.

Office Complex

The office complex in which the Partnership conducts its operations is owned by GLPL, and leased by the Partnership. Lease payments are made to GLPL on a monthly basis, with the annual lease cost for 2013 equal to $331 (2012 - $327).

Communication Equipment

The Partnership uses various types of communication assets including Supervisory Control and Data Acquisition ("SCADA") equipment, and a fiber optic network. The communication equipment is owned by GLPL and is licensed by the Partnership. License fee payments are made to GLPL on a quarterly basis, with the annual lease cost for 2013 equal to $377 (2012 – $438). Effective Q3 2013, the Partnership owns and operates a stand-alone SCADA system.

The Partnership owns Radio Systems Assets and issues licenses for the use of these assets to GLPL. License fee payments are received from GLPL on a quarterly basis, with the annual lease payments for 2013 equal to $35 (2012 - $33).

Pole Rental

The Partnership owns transmission poles and receives license fee payments in accordance with a Licensed Attachment Agreement between the Partnership and GLPL. This agreement allows GLPL to affix and maintain its apparatus and equipment to the transmission poles owned by the Partnership. Payments are received by the Partnership annually. Total payments received by the Partnership in 2013 are equal to $33 (2012 - $33).

Road Maintenance

The Partnership shares a remote roadway in the northern portion of its service territory with GLPL. The roadway is used for access to various generating stations and transmission stations. The road maintenance costs are shared between the Partnership and GLPL, with GLPL incurring the initial cost and passing a predetermined portion on to the Partnership. Payments for this road maintenance are made to GLPL as the costs are incurred by GLPL, with the total portion borne by the Partnership in 2013 being equal to $92 (2012 - $150).

(expressed in thousands of Canadian dollars)

21. RELATED PARTY TRANSACTIONS AND BALANCES (continued)

Corporate Costs

In accordance with the Services Agreement between BIH and the Partnership in effect January 1, 2012 until January 1, 2017, the Partnership records a corporate cost allocation for services received. The Partnership may request such services as but not limited to information technology management, human resource administration, and financial administration. The total corporate cost allocation recorded as an expense in 2013 was $400 (2012 - $200).

(c) The partnership incurs costs on behalf of GLPT EWT LP, a related party through common control, for development of a new transmission line. As costs are incurred by the partnership for GLPT EWT LP they are recorded as a related party receivable, and subsequently collected from GLPT EWT LP. At December 31, 2013, the outstanding receivable balance was $0 (2012 - $1,116). On August 7, 2013 the OEB issued a Decision and Order designated Upper Canada Transmission to undertake the development work related to the East West Tie Line.

(d) As a result, the following balances are receivable (payable) as at:

	Dec 31, 2013	Dec 31, 2012	Jan 1, 2012
Due from related parties			
Services provided to entities under common control	$ 36	$ 51	$ 41
Loan receivable from BIP	-	500	1,000
Receivable from GLPT EWT	-	1,116	-
	$ 36	$ 1,667	$ 1,041
Due to related parties			
Services received from entities under common control	$ 585	$ 397	$ 195

(f) Transactions with key management personnel

A summary of key management and director compensation for the year ended December 31 is as follows:

	2013	2012
Salaries, management bonus and fees	$ 808	$ 922
Other benefits	245	261
Director fees	15	15
	$ 1,068	$ 1,198

22. FIRST-TIME ADOPTION OF IFRS

IFRS 1 which establishes the basis for preparation of first-time adoption of IFRS mandates that the same accounting policies for all periods presented as part of the first financial statements issued under IFRS are presented.

The Partnership's accounting policies under IFRS are presented in Note 3 and have been applied in preparing the financial statements as at December 31, 2013, the comparative information and the opening statement of financial position at the date of transition.

Elected exemptions from full retrospective application

IFRS 1 requires the retrospective application of accounting policies to determine the opening statement of financial position at the Transition Date, January 1, 2012 and allows certain exemptions on such transition. The Partnership has elected the following optional exemptions to be applied in the preparation of its opening statement of financial position:

(i) Deemed Cost
IFRS 1 allows a rate-regulated entity to initially measure an item of property, plant and equipment upon transition to IFRS at the carrying value on the transition date and use that carrying value as the deemed cost on the opening statement of financial position. The Partnership applied this exemption and used the carrying value of all assets classified as property, plant and equipment as the deemed cost in its opening statement of financial position to establish carrying values for property, plant and equipment of $229,728.

(ii) Actuarial Gains and Losses
IFRS 1 allows an election to set actuarial gains and losses to zero and recognize these gains/losses in the opening retained earnings (deficit). The Partnership applied this exemption and all actuarial gains and losses prior the adoption of IFRS have been reset to zero.

(iii) Borrowing Costs
IFRS 1 allows the capitalization of borrowing costs prospectively to new qualifying assets, or retrospectively to assets whose construction, manufacture or production commences at an earlier specified date. The Partnership applied this exemption and prospectively accounts for borrowing costs related to "qualifying assets" in accordance with IAS 23.

Mandatory exceptions to retrospective application

As required under IFRS 1, the Partnership applied the following mandatory exceptions as follows:

(i) Estimates
The Partnership did not apply hindsight to create or revise estimates and accordingly, the estimates used under Canadian GAAP are consistent with the estimates used under IFRS.

22. FIRST-TIME ADOPTION OF IFRS (continued)

The Partnership's transition from Canadian GAAP to IFRS has resulted in adjustments to its statement of financial position, statement of income, statement of comprehensive income (loss), and statement of cash flows for the year ended December 31, 2012, and the statement of financial position as at January 1, 2012. Please refer below for a reconciliation of Canadian GAAP to IFRS.

Balance Affected	Note
Regulatory assets/liability	A
Intangible assets	B
Pension liability	C
Property, plant and equipment	D
Borrowing costs	E
Reclassifications	F

(expressed in thousands of Canadian dollars)

22. FIRST-TIME ADOPTION OF IFRS (continued)

The January 1, 2012 Canadian GAAP consolidated statement of financial position has been reconciled to IFRS as follows:

As at January 1, 2012	Canadian GAAP	Adjustments	IFRS Adjusted Balance	Note Reference
Assets				
Current Assets				
Cash	$ 219	-	$ 219	
Trade and other receivables	2,980	-	2,980	
Due from related parties	1,041	-	1,041	
Prepaid expenses and other	559	-	559	
Current portion of regulatory asset	-	-	-	
	4,799	-	4,799	
Pension asset	2,719	(2,719)	-	C
Regulatory asset	5,023	(5,023)	-	A
Property, plant and equipment, net	229,728	(3,928)	225,800	B
Intangible assets, net	-	3,928	3,928	B
	$ 242,269	(7,742)	$ 234,527	
Liabilities				
Current Liabilities				
Trade and other payables	$ 3,786	-	$ 3,786	
Current portion of regulatory liability	1,676	(1,676)	-	A
Due to related parties	195	-	195	
Current portion of trans senior bonds	-	-	-	
	5,657	(1,676)	3,981	
Pension liability	2,340	3,334	5,674	C
Regulatory liability	3,017	(3,017)	-	A
Trans senior bonds	117,341	-	117,341	
	128,355	(1,359)	126,996	
Partners' equity	113,914	(6,383)	107,531	A,C
	$ 242,269	(7,742)	$ 234,527	

(expressed in thousands of Canadian dollars)

22. FIRST-TIME ADOPTION OF IFRS (continued)

The Canadian GAAP statement of financial position at December 31, 2012 has been reconciled to IFRS as follows:

As at December 31, 2012	Canadian GAAP	Adjustments	IFRS Adjusted Balance	Note Reference
Assets				
Current Assets				
Cash	$ 182	-	$ 182	
Trade and other receivables	3,013	44	3,057	F
Due from related parties	1,667	-	1,667	
Prepaid expenses and other	806	-	806	
Current portion of regulatory asset	194	(194)	-	A
	5,862	(150)	5,712	
Pension asset	3,174	(3,174)	-	C
Regulatory asset	2,584	(2,584)	-	A
Property, plant and equipment, net	233,719	(3,510)	230,209	D,B,E
Intangible assets, net	-	3,707	3,707	B,E
	$ 245,339	(5,711)	$ 239,628	
Liabilities				
Current Liabilities				
Trade and other payables	$ 2,837	44	$ 2,881	F
Current portion of regulatory liability	1,011	(1,011)	-	A
Due to related parties	397	-	397	
Current portion of trans senior bonds	973	-	973	
	5,218	(967)	4,251	
Pension liability	2,792	6,166	8,958	C
Regulatory liability	2,021	(2,021)	-	A
Trans senior bonds	116,542	-	116,542	
	126,573	3,178	129,751	
		-	-	
Partners' equity	118,766	(8,889)	109,877	A,C,D,E
	$ 245,339	(5,711)	$ 239,628	

(expressed in thousands of Canadian dollars)

22. FIRST-TIME ADOPTION OF IFRS (continued)

The Canadian GAAP income statement for the year ended December 31, 2012 has been reconciled to IFRS as follows:

For the year ending December 31, 2012	Canadian GAAP	Adjustments	IFRS Adjusted Balance	Note Reference
Revenues	$ 37,663	(842)	$ 36,821	A
Operating Expenses				
Operating and administration	7,730	204	7,934	A,C
Depreciation and amortization	8,201	399	8,600	D,E
Maintenance	1,681	-	1,681	
Taxes, other than income taxes	108	-	108	
	17,720	603	18,323	
Net operating income	19,943	(1,445)	18,498	
Finance income	-	(27)	(27)	F
Finance costs	-	6,785	6,785	F,E
Interest expense	7,424	(7,424)	-	F,A
Loss / (gain) on disposal of property, plant and equipment	(24)	863	839	A
Other income	191	(2,652)	(2,461)	A
Income for the year before taxes	12,352	1,010	13,362	
Current tax provision	-	-	-	
Future tax provision	-	-	-	
Income for the year	$ 12,352	1,010	$ 13,362	

The Canadian GAAP statement of partners' equity for the year ended December 31, 2012 has been reconciled to IFRS as follows:

	Canadian GAAP	Adjustments	IFRS	Note Reference
Balance January 1, 2012	$ 113,914	(6,383)	$ 107,531	A,C
Net income	12,352	969	13,321	
Distributions paid	(12,000)	-	(12,000)	
Capital contributions	4,500	-	4,500	
Other comprehensive loss	-	(3,516)	(3,516)	C
Balance at December 31, 2012	**$ 118,766**	**(8,930)**	**$ 109,836**	

22. FIRST-TIME ADOPTION OF IFRS (continued)

Notes to the IFRS reconciliations above:

(A) Regulatory Asset/Liability

IFRS does not permit the recognition of regulatory assets and liabilities as these assets/liabilities do not meet the recognition criteria to be considered assets/liabilities.

Under Canadian GAAP, rate regulated asset/liabilities were permitted and hence, the partnership reported regulatory assets and liabilities. In accordance to IFRS, rate regulated accounting is not allowed and hence the Partnership eliminated its regulatory assets and liabilities with the corresponding adjustments to the profit and loss for the year ended December 31, 2012 and partners' equity as at January 1, 2012.

(B) Intangible Assets

Under Canadian GAAP, the Partnership classified land clearing rights and computer software together with property, plant and equipment within the Partnership's balance sheet.

The Partnership established that IFRS, through IAS 38, requires that assets that meet the recognition criteria to be classified as intangible assets need to be shown separately as such in the statement of financial position.

The Partnership recognized that land clearing rights and computer software meet the definition of intangible assets and hence upon transition to IFRS, reclassified these assets as intangible assets.

(C) Employee Benefits

IFRS 1 provides the option under IAS 19R to retrospectively measure Plans assets or liabilities as determined under IAS 19R or to recognize cumulative actuarial gains and losses and unrecognized past service costs and benefits deferred under Canadian GAAP in opening retained earnings at the Transition Date. The Partnership has elected to recognize all cumulative actuarial losses and unrecognized past service costs that existed at the Transition Date in opening partners' equity for all of its Plans.

IAS 19R requires the recognition of changes in the Plans obligations and in fair value of plan assets when they occur, and hence eliminates the corridor approach applied under Canadian GAAP. IAS 19R also requires all actuarial gains and losses to be immediately recognized in other comprehensive income rather than profit and loss as required under Canadian GAAP, and requires expected returns on plan assets recognized in profit or loss to be calculated using one discount rate to discount the Plans obligations compared to Canadian GAAP requiring the Partnership to apply the discount rate to each Plan.

The changes from Canadian GAAP to IFRS impacted the pension asset and liability, pension expense as well as the recognition of $3,516 as part of other comprehensive income.

(D) Property, Plant and Equipment

Canadian GAAP required that the cost of an item of property, plant and equipment made up of significant separable component parts be allocated to the component parts when practicable.

IFRS required that each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item be depreciated separately.

As a result of this difference, the Partnership conducted an analysis of all assets classified as property, plant and equipment to identify and allocate the amount recognized on transition to IFRS to its significant

22. FIRST-TIME ADOPTION OF IFRS (continued)

parts and its associated useful life. This revised allocation of significant cost components and associated useful lives resulted in an adjustment to the profit and loss for the year ended December 31, 2012.

(E) Borrowing Costs

IFRS states that borrowing costs directly attributable to the acquisition, construction, or production of a qualifying asset should to be capitalized to form part of the cost of that asset. Such borrowing costs are capitalized as part of the cost of the asset when it is probable that they will result in future economic benefits to the entity and the costs can be measured reliably.

While not an explicit requirement under Canadian GAAP the Partnership elected to capitalize interest on qualifying assets historically, however under Canadian GAAP, rate regulated entities had to abide by the capitalization rate dictated by the OEB.

Upon transition to IFRS, the Partnership is not subjected to rate regulated restrictions and is required to determine the amount of borrowing costs eligible for capitalization as the actual borrowing costs incurred on the specific borrowings during the period. Applying this key difference resulted in the Partnership increasing the borrowing costs capitalized under to property, plant and equipment and intangible assets in the statement of financial position as at December 31, 2012, with a corresponding decrease in financing costs in the statement of income and other comprehensive income (loss) for the year ended December 31, 2012.

(F) Reclassifications

These reclassifications were made for presentation purposes under IFRS.

Financial Statements

GREAT LAKES POWER TRANSMISSION LIMITED PARTNERSHIP
December 31, 2014

Deloitte.

Deloitte LLP
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Canada

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Independent Auditor's Report

To the Partners of
Great Lakes Power Transmission Limited Partnership

We have audited the accompanying financial statements of Great Lakes Power Transmission Limited Partnership, which comprise the statement of financial position as at December 31, 2014 and the statement of comprehensive income, statement of changes in partners' equity and statement of 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 International Financial Reporting Standards, 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.

Auditor's 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 auditor's 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, 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 financial statements present fairly, in all material respects, the financial position of Great Lakes Power Transmission Limited Partnership as at December 31, 2014, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
April 1, 2015
Toronto, Canada

Great Lakes Power Transmission Limited Partnership
Statement of Financial Position
Expressed in thousands of Canadian dollars

	Note		December 31, 2014		December 31, 2013
Assets					
Current Assets					
Cash		$	5,201	$	5,593
Trade and other receivables			3,422		3,476
Due from related parties	20		89		36
Prepaid expenses and other			696		370
			9,408		9,475
Property, plant and equipment, net	5		219,941		225,085
Intangible assets, net	6		2,742		3,162
		$	232,091	$	237,722
Liabilities					
Current liabilities					
Trade and other payables	7	$	3,223	$	2,973
Due to related parties	20		218		585
Current portion of Trans senior bonds	9		2,180		2,043
			5,621		5,601
Pension liability	8		7,677		7,052
Trans senior bonds	9		112,743		114,719
			126,041		127,372
Partners' equity			106,050		110,350
		$	232,091	$	237,722

Great Lakes Power Transmission Limited Partnership

Statement of Changes in Partners' Equity

Expressed in thousands of Canadian dollars

	Capital: Great Lakes Power Transmission Holdings LP	Capital: Great Lakes Power Transmission Inc.	Accumulated other comprehensive loss	Retained earnings (deficit)	Total partners' equity
Balance at January 1, 2014	**$ 112,405**	**$ 11**	**$ (1,298)**	**$ (768)**	**$ 110,350**
Net income	-	-	-	11,663	11,663
Distributions paid	-	-	-	(14,838)	(14,838)
Other comprehensive loss	-	-	(1,125)	-	(1,125)
Balance at December 31, 2014	**$ 112,405**	**$ 11**	**$ (2,423)**	**$ (3,943)**	**$ 106,050**

	Capital: Great Lakes Power Transmission Holdings LP	Capital: Great Lakes Power Transmission Inc.	Accumulated other comprehensive income (loss)	Retained earnings (deficit)	Total partners' equity
Balance at January 1, 2013	$ 112,405	$ 11	$ (3,516)	$ 977	109,877
Net income	-	-	-	11,178	11,178
Distributions paid	-	-	-	(12,923)	(12,923)
Other comprehensive income	-	-	2,218	-	2,218
Balance at December 31, 2013	$ 112,405	$ 11	$ (1,298)	$ (768)	$ 110,350

Great Lakes Power Transmission Limited Partnership

Statement of Comprehensive Income

Expressed in thousands of Canadian dollars

Years ended December 31,	*Note*		**2014**		2013
Revenue		$	**39,805**	$	39,640
Operating expenses					
Operating and administration	*12*		**9,122**		8,858
Depreciation and amortization	*15*		**9,302**		9,284
Maintenance	*13*		**1,573**		1,861
Taxes, other than income taxes			**107**		107
			20,104		20,109
Net operating income			**19,701**		19,531
Finance income			**(66)**		(47)
Finance costs	*14*		**7,901**		7,947
Loss on disposal of property, plant and equipment and intangible assets	*5,6*		**215**		453
Other income			**(12)**		-
Income for the year			**11,663**		11,178
Other comprehensive (loss) income					
Items that will not be reclassified subsequently to profit or loss:					
Remeasurement of pension liability	*8*		**(1,125)**		2,218
Total comprehensive income		$	**10,538**	$	13,396

Great Lakes Power Transmission Limited Partnership

Statement of Cash Flows

Expressed in thousands of Canadian dollars

Years ended December 31,	*Note*		**2014**		2013
Operating Activities					
Income for the year		$	**11,663**	$	11,178
Items not affecting cash					
Depreciation and amortization	*15*		**9,302**		9,284
Finance costs	*14*		**7,901**		7,947
Loss on disposal of property, plant and equipment and intangible assets	*5,6*		**215**		453
Net change in non-cash working capital and other	*17*		**(942)**		2,681
Operating cash flows before interest			**28,139**		31,543
Cash interest paid			**(7,823)**		(7,920)
			20,316		23,623
Investing activities					
Proceeds on disposition of property, plant and equipment and intangible assets	*5,6*		**18**		18
Additions to property, plant and equipment and intangible assets			**(3,845)**		(4,334)
			(3,827)		(4,316)
Financing activities					
Principal repayments on Trans senior bonds			**(2,043)**		(973)
Distributions paid			**(14,838)**		(12,923)
			(16,881)		(13,896)
(Decrease) increase in cash			**(392)**		5,411
Cash, beginning balance			**5,593**		182
Cash, ending balance		$	**5,201**	$	5,593

1. GENERAL INFORMATION

Ontario-based Great Lakes Power Transmission Limited Partnership (the "Partnership") was formed on May 17, 2007 for the purpose of acquiring the assets and liabilities of the transmission division of Great Lakes Power Limited ("GLPL"), a related party due to common ownership. The address of the Partnership's registered office is 2 Sackville Road, Suite B, Sault Ste. Marie, Ontario, Canada, P6B 6J6.

Effective March 26, 2013, the shareholders of the Partnership entered into a series of transactions which resulted in the Limited Partner, Brookfield Infrastructure Holdings (Canada) Inc. ("BIH") transferring its 20,285,007 Class A Units of the Partnership to newly formed Great Lakes Power Transmission Holdings LP in exchange for 145,984,400 Class A Units of Great Lakes Power Transmission Holdings LP. There was no change in the General Partner.

Great Lakes Power Transmission Holdings LP is the Limited Partner and holds a 99.99% interest in the Partnership. Great Lakes Power Transmission Inc., the General Partner, holds a 0.01% limited interest in the Partnership and is responsible for management of the Partnership. Both the General and Limited Partners are wholly owned subsidiaries of Brookfield Infrastructure Partners LP ("BIP"), the ultimate parent company and controlling party of the group.

The Partnership is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board ("OEB").

2. BASIS OF PRESENTATION

Statement of compliance

These financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Accounting policies are consistently applied to both years presented, unless otherwise stated.

The financial statements were approved and authorized for issue by those charged with governance of the Partnership on April 1, 2015.

Basis of measurement

The financial statements have been prepared on a going concern assumption using the historical cost basis except where otherwise noted. Historical cost is generally based on the fair value of the consideration given in exchange for assets or settlement of liabilities as at the date the transaction occurs.

Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Partnership's functional currency. All amounts have been rounded to the nearest thousand, unless otherwise indicated.

Critical judgments and estimation uncertainties

In the preparation of these financial statements in conformity with IFRS, management makes judgments, estimates and assumptions that affect the application of accounting policies and the

2. BASIS OF PRESENTATION (continued)

reported amounts of revenues, expenses, assets and liabilities. Facts and circumstances may change and actual results could differ from those estimates.

Estimates and Judgments

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Information about critical judgments and estimates in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are included in the following notes:

Impairment

Assets, including property, plant and equipment and intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. Intangible assets with indefinite useful lives are tested for impairment annually and whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. The assessment of fair value often requires estimates and assumptions on items such as discount rates, rehabilitation and restoration costs, future capital requirements and future operating performance. Changes in such estimates could impact recoverable values of these assets. Estimates are reviewed annually by management.

Judgment is involved in assessing whether there is any indication that an asset or cash generating unit ("CGU") may be impaired. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets. This assessment is made based on the analysis of changes in the market or business environment, and events that have transpired that have impacted the asset or CGU.

Depreciation of property, plant and equipment and intangible assets

Each property, plant and equipment and intangible asset is assessed annually for both its physical life limitations and its economic recoverability. Those assets with a finite life are depreciated on a straight-line basis over a useful life estimated by management. Asset useful lives and residual values are re-evaluated annually. At December 31, 2014 the carrying value of property plant and equipment and intangible assets is $219,941 (2013 - $225,085) and $2,742 (2013 - $3,162) respectively.

Fair value disclosures of Trans senior bonds

The Partnership has estimated the fair value of its Trans senior bonds for disclosure purposes, as they are not separately traded. The fair value is based on future cash flows and the timing of settlement, along with assumptions about the discount rate, credit risk and by incorporating other assumptions made by market participants. At December 31, 2014 the carrying value of Trans senior bonds is $114,923 (2013 - $116,762).

Pension

Significant estimates and assumptions are made in determining pension and employee future benefits as there are numerous factors that will affect the pension obligation. The actuarial

2. BASIS OF PRESENTATION (continued)

determination of the accrued benefit obligation for pensions and post-employment benefits uses the projected unit credit method prorated on service which incorporates management's best estimate of future salary levels, other cost escalation, mortality rates, retirement ages of employees and other actuarial factors. In addition, actuarial determinations used in estimating obligations relating to the defined benefit plans incorporate assumptions using management's best estimates of factors including plan performance, salary escalation, retirement dates of employees and drug cost escalation rates. At December 31, 2014 the carrying value of pension liabilities is $7,677 (2013 - $7,052).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Partnership has consistently applied the following accounting policies to both periods presented in these financial statements:

Financial instruments

The Partnership recognizes all financial instruments at fair value upon initial recognition and subsequently classifies them into one of the following categories: Financial assets and financial liabilities at fair value through profit or loss, held-to-maturity, loans and receivables, available-for-sale and other liabilities. As at December 31, 2014, the Partnership only holds the following financial instruments: Trade and other payables, long-term debt (which are classified as other financial liabilities) and trade receivables (which are classified as loans and receivables).

The Partnership initially recognizes other financial liabilities and loans and receivables on the trade date. The Partnership derecognizes its financial liability when its contractual obligations are discharged, cancelled, or expired.

Other financial liabilities including borrowings are initially measured at fair value net of transaction costs, and subsequently measured at amortized cost using the effective interest method. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Property, plant and equipment

Recognition and measurement

Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. The cost of major inspections or overhauls is capitalized and costs relating to the replacement of a major part of property, plant and equipment are recognized in the carrying amount of the asset to which that part relates, if it is probable that the inspection, overhaul or replacement part will generate future economic benefits and its cost can be measured reliably. The carrying amount of previous inspections and overhauls, or the part being replaced is derecognized and any gain or loss is recognized against income. The cost of the day-to-day servicing of property, plant and equipment is recognized in Operating and administration or maintenance expense as incurred.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Costs included in the carrying amount of property, plant and equipment include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads.

Borrowing costs associated with major projects are capitalized during the construction period, if those projects meet the definition of a qualifying asset, meaning those projects that are under construction for a substantial period of time. Capitalization of borrowing costs is suspended during extended periods in which construction development is interrupted. Assets under construction are recorded as work-in-progress until they become available for use.

When property, plant and equipment is disposed of or retired, the related cost, accumulated depreciation and any accumulated impairment losses are eliminated. Any resulting gains or losses are reflected against income in the period the asset is disposed of or retired.

Depreciation

The cost, net of estimated residual values, of an asset classified as property, plant and equipment is amortized over the estimated useful life of the asset using a straight-line method. Land is not depreciated.

The estimated useful lives of property, plant and equipment are as follows:

	Method	Rate
Transmission assets	Straight-line	5 to 60 years
Equipment and other assets	Straight-line	5 to 30 years

The estimated useful lives, residual values and method of depreciation are based on depreciation studies and are reviewed annually for reasonableness.

Construction work-in-progress assets are not depreciated until the assets become available for their intended use.

Impairment

At each reporting date, the Partnership reviews the carrying amount of its non-financial assets to determine whether there is any indication of impairment. Impairment assessments are conducted at the CGU level. If any such indication exists, the recoverable amount of the CGU is estimated.

The recoverable amount of the CGU is the greater of its value in use and its fair value less costs to sell. Value in use is based on the estimated future cash flows, discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized against income if the carrying amount of a CGU exceeds its recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If such indications exist, the

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Partnership estimates the recoverable amount of that CGU. A reversal of an impairment loss is recognized up to the lesser of the recoverable amount or the carrying amount that would have been determined (net of depreciation charges) had no impairment loss been recognized on the CGU.

Intangible assets

Acquired intangible assets having finite useful lives are measured at cost less accumulated amortization and any accumulated impairment losses. Intangible assets are capitalized if: (i) It is probable that the asset acquired or developed will generate future economic benefits, (ii) intangibles are identifiable, and (iii) the Partnership exerts control over the economic benefit to be derived from the asset. The costs incurred to establish technological feasibility or to maintain existing levels of performance are recognized in operating or maintenance expense as incurred.

The carrying costs of intangible assets include expenditures that are directly attributable to the acquisition or development of the asset. The cost of self-developed assets includes materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects (qualifying assets) are capitalized during the development period. Qualifying assets are those projects that are under development for a substantial period of time. Assets under development are recorded as in progress until they become available for use.

Subsequent expenditures are capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. All other expenditures are recognized against income as incurred.

Amortization is based on the cost of the asset less its residual value and is calculated using the straight-line method over the estimated useful life of the asset from the date the asset is available for use, and is generally recognized against income. The useful lives of intangible assets range from 5 to 15 years. Land rights with indefinite lives are not amortized.

The estimated useful lives, residual values and method of amortization are reviewed annually for reasonableness.

Intangible assets with an indefinite life are tested for impairment on an annual basis.

Employee benefits

Short-term employee benefits

Short-term employee benefits are expensed as the related service is provided by the employee. A liability is recognized for the amount expected to be paid if the Partnership has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

Defined contribution plans

Obligations for contributions to defined contribution plans are expensed as the related service is provided by the employee. Prepaid contributions are recognized as an asset to the extent that a cash refund or a reduction in future payments is available.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Defined benefit plans

The Partnership's net obligation in respect to defined benefit plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in the current and prior periods, discounting that amount and deducting the fair value of any plan assets.

The calculation of defined benefit obligations is performed annually by a qualified actuary using the projected unit credit method. When the calculation results in a potential asset for the Partnership, the recognized asset is limited to the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. To calculate the present value of economic benefits, consideration is given to any applicable minimum funding requirements.

Remeasurements of the net defined benefit liability, which comprise actuarial gains and losses, the return on plan assets (excluding interest) and the effect of the asset ceiling (if any, excluding interest), are recognized immediately in other comprehensive income. The Partnership determines the net interest expense (income) on the net defined benefit liability (asset) for the period by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the then-net defined benefit liability (asset), taking into account any changes in the net defined benefit liability (asset) during the period as a result of contributions and benefit payments. Net interest expense and other expenses related to defined benefit plans are recognized against income.

When the benefits of a plan are changed or when a plan is curtailed, the resulting change in benefit that relates to past service or the gain or loss on curtailment is recognized immediately against income. The Partnership recognizes gains and losses on the settlement of a defined benefit plan when the settlement occurs. The gain or loss on curtailment or settlement comprises any resulting change in the fair value of plan assets, any change in the present value of the defined benefit obligation, and any relating actuarial gains or losses and past service costs that had not been previously been recognized.

Other long-term employee benefits

The Partnership's net obligation in respect of long-term employee benefits is the amount of future benefit that employees have earned in return for their service in the current and prior periods. That benefit is discounted to determine its present value. Remeasurements are recognized against income in the period in which they arise.

Revenue

Revenue is measured at the fair value of the consideration received or receivable. Revenue is recognized by the Partnership when a sales arrangement exists, delivery of goods or services has occurred, the amount of revenue and costs incurred or to be incurred in respect of the transaction can be measured reliably and it is probable that future economic benefits will flow to the Partnership.

The Partnership recognizes revenue on an accrual basis, when electricity is wheeled, at the regulated rate established by the OEB.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Foreign currency

Transactions in foreign currencies are translated to the functional currency of the Partnership at exchange rates at the dates of the transactions.

Borrowing costs

Borrowing costs that are directly attributable to the acquisition, construction or development of a qualifying asset are added to the cost of that asset, until it is available for use. Qualifying assets are those that take a substantial period of time to get ready for their intended use. The Partnership capitalizes borrowing costs by applying its cost of debt. All other borrowing costs are recognized in finance expense in the period in which they are incurred.

Changes in accounting policies

The Partnership has adopted the following new and revised IFRS policies along with any amendments, effective January 1, 2014. These changes were made in accordance with the applicable transitional provisions.

IFRIC 21, Levies

IFRIC 21, Levies ("IFRIC 21"), an interpretation of IAS 37, Provisions, Contingent Liabilities and Contingent Assets ("IAS 37"), on the accounting for levies imposed by governments was issued by the IASB in May 2013. IAS 37 sets out criteria for the recognition of a liability, one of which is the requirement for the entity to have a present obligation as a result of a past event ("obligating event"). IFRIC 21 clarifies that the obligating event that gives rise to a liability to pay a levy is the activity described in the relevant legislation that triggers the payment of the levy. The adoption of IFRIC 21 did not have a significant impact on the Partnership's financial statements.

IAS 32, Financial instruments: presentation

IAS 32, Financial instruments: presentation ("IAS 32"), was amended by the IASB in December 2011. The amendment clarifies that an entity has a legally enforceable right to offset financial assets and financial liabilities if that right is not contingent on a future event and it is enforceable both in the normal course of business and in the event of default, insolvency or bankruptcy of the entity and all counterparties. The adoption of this standard did not have any significant impact on the Partnership's financial statements.

IAS 36, Impairment of assets

IAS 36, Impairment of assets ("IAS 36"), was amended by the IASB in May 2013. The amendment requires the disclosure of the recoverable amount of impaired assets when an impairment loss has been recognized or reversed during the period and additional disclosures about the measurement of the recoverable amount of impaired assets when the recoverable amount is based on fair value less costs of disposal, including the discount rate when a present value technique is used to measure the recoverable amount. The adoption of this standard did not have any significant impact on the Partnership's financial statements.

4. FUTURE CHANGES IN ACCOUNTING POLICIES

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning after December 31, 2014 and have not been applied in preparing these financial statements. Those which may be relevant to the Partnership are set out below. The Partnership does not plan to early adopt any of these standards.

Depreciation

On May 12, 2014, the IASB issued amendments to IAS 16, Property, Plant and Equipment ("IAS 16"), and IAS 38, Intangible Assets ("IAS 38"). In issuing the amendments, the IASB has clarified that the use of revenue-based methods to calculate the depreciation of a tangible asset is not appropriate because revenue generated by an activity that includes the use of a tangible asset generally reflects factors other than the consumption of the economic benefits embodied in the asset. The IASB has also clarified that revenue is generally presumed to be an inappropriate basis for measuring the consumption of the economic benefits embodied in an intangible asset. This presumption for an intangible asset, however, can be rebutted in certain limited circumstances. The standard is to be applied prospectively for reporting periods beginning on or after January 1, 2016 with early application permitted. The Partnership is currently evaluating the impact of applying the amendments but does not anticipate that there will be any impact on its current method of calculating depreciation or amortization.

Revenue

On May 28, 2014 the IASB issued IFRS 15, Revenue from Contracts with Customers ("IFRS 15"). This standard outlines a single comprehensive model with prescriptive guidance for entities to use in accounting for revenue arising from contracts with its customers. IFRS 15 uses a control based approach to recognize revenue which is a change from the risk and reward approach under the current standard. This standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. The effective date is for reporting periods beginning on or after January 1, 2017 with early application permitted. The Partnership has not yet determined the effect of adoption of IFRS 15 on its financial statements.

Financial instruments

On July 24, 2014 the IASB issued IFRS 9, Financial Instruments ("IFRS 9") as a complete standard. This standard replaces the guidance in IAS 39 Financial Instruments: Recognition and Measurement on the classification and measurement of financial assets and financial liabilities. IFRS 9 utilizes a single approach to determine whether a financial asset is measured at amortized cost or fair value and a new mixed measurement model for debt instruments having only two categories: amortized cost and fair value. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. Final amendments released on July 24, 2014 also introduce a new expected loss impairment model and limited changes to the classification and measurement requirements for financial assets. The IASB has tentatively decided to require an entity to apply IFRS 9 for annual periods beginning on or after January 1, 2018. The Partnership has not yet determined the effect of adoption of IFRS 9 on its financial statements.

4. FUTURE CHANGES IN ACCOUNTING POLICIES (continued)

Fair Value Measurement

On December 12, 2013 the IASB amended IFRS 13, Fair Value Measurement ("IFRS 13"). The amendments clarify that the portfolio exception applies to all contracts within the scope of IAS 39, Financial Instruments: Recognition and Measurement ("IAS 39") or IFRS 9 regardless of whether they are financial assets or financial liabilities. The amendments are effective for annual periods beginning on or after July 1, 2014. The adoption of these amendments is not expected to have a significant impact on the Partnership's financial statements.

Presentation of Financial Statements

On December 18, 2014 the IASB amended IAS 1, Presentation of Financial Statements ("IAS 1"). The amendments to existing IAS 1 requirements relate to materiality; order of the notes; subtotals; accounting policies; and disaggregation. The amendments are effective for annual periods beginning on or after January 1, 2016. The adoption of these amendments is not expected to have a significant impact on the Partnership's financial statements.

Employee Benefits

On November 13, 2013 the IASB amended IAS 19, Employee Benefits ("IAS 19"). The amendments provide additional guidance to IAS 19 on the accounting for contributions from employees or third parties set out in the formal terms of a defined benefit plan. The amendments are effective for annual periods beginning on or after July 1, 2014. IAS 19 was further amended on July 30, 2014. The amendments to IAS 19 clarify the application of the requirements of IAS 19 on determination of the discount rate to a regional market consisting of multiple countries sharing the same currency. The amendments are effective for annual periods beginning on or after January 1, 2016. The adoption of these amendments is not expected to have a significant impact on the Partnership's financial statements.

Related Party Disclosures

On December 12, 2013 the IASB amended IAS 24, Related Party Disclosures ("IAS 24"). The amendments clarify the identification and disclosure requirements for related party transactions when key management personnel services are provided by a management entity. The amendments are effective for annual periods beginning on or after July 1, 2014. The adoption of these amendments is not expected to have a significant impact on the Partnership's financial statements.

(expressed in thousands of Canadian dollars)

5. PROPERTY, PLANT AND EQUIPMENT, NET

	Land	Equipment and other assets	Transmission assets	Work-in-progress	Total
Cost					
Balance, December 31, 2012	$ 236	$ 8,111	$ 227,584	$ 2,327	$ 238,258
Additions	-	-	-	4,071	4,071
Transfers	-	1,354	3,103	(4,457)	-
Disposals	-	(5)	(542)	-	(547)
Balance, December 31, 2013	$ 236	$ 9,460	$ 230,145	$ 1,941	$ 241,782
Additions	-	-	--	4,044	4,044
Transfers	--	540	3,726	(4,266)	-
Disposals	-	(6)	(322)	(102)	(430)
Balance, December 31, 2014	$ 236	$ 9,994	$ 233,549	$ 1,617	$ 245,396
Accumulated Depreciation					
Balance, December 31, 2012	$ -	$ 587	$ 7,462	$ -	$ 8,049
Additions	-	832	7,894	-	8,726
Disposals	-	(5)	(73)	-	(78)
Balance, December 31, 2013	$ -	$ 1,414	$ 15,283	$ -	$ 16,697
Additions	-	920	7,933	-	8,853
Disposals	-	(6)	(89)	-	(95)
Balance, December 31, 2014	$ -	$ 2,328	$ 23,127	$ -	$ 25,455
Carrying amounts					
Balance, December 31, 2013	$ 236	$ 8,046	$ 214,862	$ 1,941	$ 225,085
Balance, December 31, 2014	$ 236	$ 7,666	$ 210,422	$ 1,617	$ 219,941

During the year, the Partnership disposed of assets with a total net book value of $233 (2013 - $469) for net proceeds of $18 (2013 - $18). A resultant loss on disposal of property, plant and equipment of $215 (2013 - $451) was recorded to the statement of comprehensive income.

During the year, the Partnership wrote off $102 in work-in-progress assets, which was recorded to the statement of comprehensive income under Operations and administration expense.

(expressed in thousands of Canadian dollars)

6. INTANGIBLE ASSETS, NET

	Land rights	Computer software	Work-in-progress	Total
Cost				
Balance, December 31, 2012	$ 1,102	$ 2,842	$ 256	$ 4,200
Additions	-	-	15	15
Disposals	-	(3)	-	(3)
Balance, December 31, 2013	1,102	2,839	271	4,212
Additions	-	-	139	139
Transfers	-	46	(46)	-
Disposals	-	-	(110)	(110)
Balance, December 31, 2014	$ 1,102	$ 2,885	$ 254	$ 4,241
Accumulated Depreciation				
Balance, December 31, 2012	$ -	$ 493	$ -	$ 493
Additions	-	558	-	558
Disposals		(1)	-	(1)
Balance, December 31, 2013	-	1,050	-	1,050
Additions	-	449	-	449
Disposals	-	-	-	-
Balance, December 31, 2014	$ -	$ 1,499	$ -	$ 1,499
Carrying amounts				
Balance, December 31, 2013	$ 1,102	$ 1,789	$ 271	$ 3,162
Balance, December 31, 2014	$ 1,102	$ 1,386	$ 254	$ 2,742

During the year, the Partnership disposed of assets with a total net book value of $nil (2013 - $2) for net proceeds of $nil (2013 - $nil). A resultant loss on disposal of intangible assets of $nil (2013 - $2) was recorded to the statement of comprehensive income.

During the year, the Partnership wrote off $110 in work-in-progress assets, which was recorded to the statement of comprehensive income under Operations and administration expense.

The Partnership owns land rights and other land easements that are needed as part of the normal business operations. Land rights have been obtained through contractual rights where the transferor has transferred land rights and land easements to specific parcels of land in perpetuity. The Partnership has identified land rights as intangible assets with an indefinite useful life since contractual rights give access to specific land parcels in perpetuity. The Partnership accounts for land rights at cost less cumulative impairment losses. At December 31, 2014 the carrying amounts of land rights is $1,102 (2013 - $1,102).

The Partnership has not identified events or changes in circumstances that indicate that the land rights' carrying amounts exceed their recoverable amounts. The Partnership has tested land rights for impairment in accordance with annual impairment tests.

(expressed in thousands of Canadian dollars)

6. INTANGIBLE ASSETS, NET (continued)

The Partnership has identified the recoverable amount of land rights to be their fair values less cost of disposal. In arriving at the fair value less cost of disposal, the Partnership has used a recent sale proposal which it believes is indicative of the fair value less cost of disposal of the land rights owned. The Partnership has determined that as at December 31, 2014 the fair value less cost of disposal is greater than the carrying amount and hence no impairment loss has been recorded.

The Partnership uses fair value less cost of disposal to determine the recoverable amount as it believes that this will generally result in a value greater than or equal to the value in use. For the purpose of the intangible impairment test, the Partnership used a non-binding sale agreement. The inputs used in the fair value measurement constitute Level 2 inputs under the fair value hierarchy. Level 2 inputs are quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets, inputs other than quoted prices that are observable for the asset or liability (for example, interest rate and yield curves observable at commonly quoted intervals, forward pricing curves used to value currency and commodity contracts), or inputs that are derived principally from or corroborated by observable market data or other means.

7. TRADE AND OTHER PAYABLES

	Dec 31, 2014	Dec 31, 2013
Trade payables and accruals	$ 955	$ 862
Payroll liabilities	527	633
Accrued interest	322	322
Connection deposits	1,076	838
Other payables	343	318
	$ 3,223	$ 2,973

The Partnership retains connection deposits for two power generating entities as reimbursement to the Partnership for costs to be incurred in connecting those power generating entities to the Partnership's power transmission property assets. Any unused connection deposit balance will be refunded to the appropriate power generating entity.

8. PENSION AND EMPLOYEE FUTURE BENEFITS

The Partnership is part of a registered defined benefit, final pay pension plan and other post-employment benefit plan (the "Plans").

The other post-employment benefit plan includes benefits such as health and dental care, and life insurance. The obligation under these plans is determined periodically through the preparation of actuarial valuations. The Partnership contributions for the benefit plans for 2014 was $1,193 (2013 - $821).

The Partnership also participates in a defined contribution pension plan provided to certain employees. The Partnership contributes based on the level of employee contributions for this plan. In 2014, the total employer expense for the Partnership's defined contribution pension plan was $140 (2013 - $119). The minimum employer's contribution for 2015 is estimated to be $976.

The Partnership's pension plan information is provided in the following tables:

(expressed in thousands of Canadian dollars)

8. PENSION AND EMPLOYEE FUTURE BENEFITS (continued)

	December 31, 2014			December 31, 2013		
	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total
Change in the present value of the accrued benefit obligation						
Balance, beginning of year	20,415	5,708	26,123	20,362	5,503	25,865
Current service cost	376	195	571	382	278	660
Past service cost	-	(315)	(315)	-	-	-
Interest expense	989	269	1,258	889	241	1,130
Benefit payments from plan	(892)	(142)	(1,034)	(756)	(140)	(896)
Employee contributions	117	-	117	132	-	132
Increases (decreases) due to other significant events	(25)	-	(25)	11	-	11
Remeasurements:						
Effect of changes in demographic assumptions	200	102	302	837	423	1,260
Effect of changes in financial assumptions	1,966	1,052	3,018	(1,507)	(597)	(2,104)
Effect of experience adjustments	(501)	-	(501)	65	-	65
Effect of changes in foreign exchange rates	-	-	-	-	-	-
Balance, end of year	22,645	6,869	29,514	20,415	5,708	26,123
Change in fair value of the plan assets						
Fair value, beginning of year	19,070	-	19,070	16,907	-	16,907
Return on plan assets	1,763	-	1,763	1,506	-	1,506
Contributions:						
Employer	1,051	142	1,193	681	140	821
Employee	117	-	117	132	-	132
Benefit payments from plan	(892)	(142)	(1,034)	(756)	(140)	(896)
Administrative expenses paid from plan assets	(208)	-	(208)	(167)	-	(167)
Interest income	956	-	956	760	-	760
Increases (decreases) due to other significant events	(20)	-	(20)	8	-	8
Fair value, end of year	21,837	-	21,837	19,071	-	19,071
Net Defined Benefit Liability						
Accrued benefit obligation	(22,645)	(6,869)	(29,514)	(20,415)	(5,708)	(26,123)
Fair value of plan assets	21,837	-	21,837	19,071	-	19,071
Net Defined Benefit Liability	(808)	(6,869)	(7,677)	(1,344)	(5,708)	(7,052)
Total expense recognized in profit and loss						
Current service cost	376	195	571	382	278	660
Past service cost	-	(315)	(315)	-	-	-
Net interest expense	32	266	298	129	244	373
Administrative expenses and taxes	140	-	140	100	-	100
Total expense recognized in profit and loss	548	146	694	611	522	1,133
Actuarial losses/(gains) recognized in statement of comprehensive income						
Effect of changes in demographic assumptions	200	102	302	837	423	1,260
Effect of changes in financial assumptions	1,966	1,052	3,018	(1,507)	(597)	(2,104)
Effect of experience adjustments	(501)	-	(501)	65	-	65
Return on plan assets	(1,694)	-	(1,694)	(1,439)	-	(1,439)
Total actuarial losses/(gains) recognized in statement of comprehensive income	(29)	1,154	1,125	(2,044)	(174)	(2,218)

Effects of changes in assumptions	Revalued pension obligation	Revalued pension obligation	Total
Discount Rate			
Increase by 100 basis points	18,745	856	19,601
Decrease by 100 basis points	25,519	1,004	26,523
Inflation Rate			
Increase by 100 basis points	23,642	925	24,567
Decrease by 100 basis points	19,871	925	20,796

Significant Actuarial Assumptions	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Defined Benefit Pension Plan	Non-Pension Benefit Plans
	December 31, 2014		December 31, 2013	
Weighted-Average actuarial assumptions used:				
Discount rate	4.00%	4.10%	4.95%	4.95%
Rate of compensation increases	3.00%	3.00%	3.00%	3.00%
Inflation Rate	2.00%	2.00%	2.00%	2.00%

Plan Assets by asset class allocation (%)	31-Dec-14	31-Dec-13
Fixed Income	33%	28%
Equities	67%	71%
Other	0%	1%
Total	100%	100%

(expressed in thousands of Canadian dollars)

9. TRANS SENIOR BONDS

The Trans Senior Bonds (the "Bonds") have a principal amount of $120,000 and are secured by a charge on the Partnership's transmission real property assets, both present and future. On behalf of the Partnership, a company related through common control, BIP, continues to maintain a letter of credit in the amount of $3,960 to cover six months of interest payments on the Bonds.

The fair market value of the Bonds as at December 31, 2014 is $144,112 based on current market prices for debt with similar terms (2013 - $139,821). Amortization of deferred financing fees for the year related to the Partnership's Bonds are included in finance costs and totalled $203 (2013 - $220).

The Bonds bear interest at the rate of 6.6% per annum. Semi-annual payments of interest only were due and payable on June and December 16 each year up until and including June 16, 2013. Equal blended semi-annual payments of principal and interest on the Bonds commenced on December 16, 2013 and will continue until and including June 16, 2023. The Bonds will not be fully amortized by their maturity date. The remaining principal balance of the Bonds will be fully due on June 16, 2023.

	Dec 31, 2014	Dec 31, 2013
Trans senior bonds	$ 116,984	$ 119,027
Less: unamortized deferred financing fees	(2,061)	(2,265)
Less: current portion	(2,180)	(2,043)
	$ 112,743	$ 114,719

As at December 31, 2014, principal repayments due in each of the next five years were as follows:

	2015	2016	2017	2018	2019
Principal repayments	$ 2,180	$ 2,327	$ 2,483	$ 2,649	$ 2,827

During the year, the Partnership identified a number of projects which were considered to be qualifying assets for purposes of capitalizing borrowing costs. For the year ended December 31, 2014, the Partnership capitalized borrowing costs of $125 (2013 - $190). The capitalization rate on funds borrowed amounted to 6.6% (2013 - 6.6%).

10. PARTNERSHIP UNITS

As described in Note 1, the Partnership's shareholders entered into a series of transactions which resulted in a change to the Limited Partner from being Brookfield Infrastructure Holdings (Canada) Inc. to Great Lakes Power Transmission Holdings LP, both related parties due to common ownership.

The Partnership is authorized to issue an unlimited number of Class A and Class B partnership units, of which 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2014. 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2013.

(expressed in thousands of Canadian dollars)

11. COMMITMENTS AND CONTINGENCIES

Letters of credit

On behalf of the Partnership, BIP continues to maintain a letter of credit totaling $3,960 to cover six months of interest payments on the Bonds. No amount has been drawn against this letter of credit.

Commitments

As at December 31, 2014 future minimum lease payments for operating leases entered into by the Partnership, as lessee, were as follows:

	2015	2016-2019	Thereafter
Minimum lease payments	$336	$1,345	$0

Contingencies

The Partnership may, from time to time, be involved in legal proceedings, claims and litigation that arises in the ordinary course of business which the Partnership believes would not reasonably be expected to have a material adverse effect on the financial condition of the Partnership.

There are no specified decommissioning costs relating to the Ontario transmission assets. The Partnership has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to optimum industry standards. Replacement of the assets occurs in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which the Partnership would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

12. OPERATING AND ADMINISTRATION EXPENSES

	2014	2013
Compensation expenses	$ 5,989	$ 5,655
Contract expenses	1,780	1,606
Materials	801	532
Other	552	1,065
	$ 9,122	$ 8,858

(expressed in thousands of Canadian dollars)

13. MAINTENANCE EXPENSES

	2014	2013
Compensation expenses	$ 393	$ 430
Contract expenses	545	736
Materials	146	146
Other	489	549
	$ 1,573	$ 1,861

14. FINANCE COSTS

	2014	2013
Interest expense on Trans senior bonds	$ 7,823	$ 7,917
Amortization of deferred financing fees on Trans senior bonds	203	220
Less: capitalized interest	(125)	(190)
	$ 7,901	$ 7,947

15. DEPRECIATION AND AMORTIZATION

	2014	2013
Depreciation on property, plant and equipment	$ 8,853	$ 8,726
Amortization of intangible assets	449	558
	$ 9,302	$ 9,284

16. INCOME TAXES

The Partnership does not record income tax expenses as it is not subject to income taxation as a result of its formation as a limited partnership.

17. STATEMENT OF CASH FLOWS

Net change in non-cash working capital related to operations

	2014	2013
Trade and other receivables	$ 54	$ (419)
Prepaid expenses and other	(326)	436
Due from related parties	(53)	1,631
Trade and other payables	250	533
Due to related parties	(367)	188
Pension liability	(500)	312
	$ (942)	$ 2,681

(expressed in thousands of Canadian dollars)

18. CAPITAL RISK MANAGEMENT

The Partnership's primary capital management objective is to ensure the sustainability of its capital to support continuing operations, meet its financial obligations, allow for growth opportunities and provide stable distributions to its partners. The Partnership manages its capital to maintain an investment grade credit rating while prudently making use of leverage in order to provide its ultimate parent with enhanced returns. In addition, the Partnership manages its capital to ensure access to incremental borrowings needed to fund new growth initiatives.

The Partnership manages its capital structure in accordance with changes in economic conditions. Generally, capital expenditures are funded with external borrowings. In order to adjust the capital structure, the Partnership may elect to adjust the distribution amount paid to its partners, increase or reduce the equity participation in new and existing operations, adjust the level of capital spending or issue new partnership units.

The Partnership manages its capital in order to maintain a debt to capitalization ratio below 75%. As at December 31, 2014, the ratio was 52% (2013 – 52%). The table below presents the detail of the Partnership's capitalization and the calculation of the ratio:

	Dec 31, 2014	Dec 31, 2013
Trans senior bonds	$ 116,984	$ 119,027
	116,984	119,027
Partners' equity	106,050	110,350
Total capitalization	$ 223,034	$ 229,377
Debt to capitalization	52%	52%

There has been no change in the Partnership's approach to managing capital in the year.

(expressed in thousands of Canadian dollars)

19. FINANCIAL INSTRUMENTS

Fair value measurement

The Partnership defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The Partnership classifies its financial assets and liabilities as outlined below:

		December 31, 2014		December 31, 2013	
	Class	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets					
Cash	LAR	$ 5,201	$ 5,201	$ 5,593	$ 5,593
Trade and other receivables	LAR	3,422	3,422	3,476	3,467
Financial liabilities					
Trade and other payables	OL	3,223	3,223	2,973	2,973
Trans senior bonds	OL	114,923	144,112	116,762	139,821

Classification details:
FVTPL – fair value through profit or loss
LAR – loans and receivables
OL – other liabilities

The statements of financial position carrying amounts for cash, trade and other receivables, prepaid expenses and other assets, trade and other payables, and due to and from related parties approximate fair value due to their short-term nature. Due to the use of subjective judgments and uncertainties in the determination of fair values, these values should not be interpreted as being realizable in an immediate settlement of the financial instruments.

Fair value hierarchy

The following provides a description of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable:

(a) Level 1 fair value measurements are those derived from quoted market prices (unadjusted) in active markets for identical assets or liabilities;
(b) Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
(c) Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

No financial instruments have been ranked level 2 or 3, except for the Bonds which are ranked as level 2.

19. FINANCIAL INSTRUMENTS (continued)

There were no transfers between Level 1, 2 and 3 during the reporting periods. The fair values of financial assets and liabilities carried at amortized cost are approximated by their carrying values, except for the Bonds whose fair market value is presented in note 9.

Financial risk management

The Partnership has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk.

The Partnership's management has overall responsibility for the establishment and oversight of the Partnership's risk management framework. Risk management policies are established to identify and analyze the risks faced by the Partnership, to set appropriate risk limits and controls and to monitor risks and ensure adherence to these limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Partnership's activities. The Partnership, through its training and management standards and procedures, aims to maintain a disciplined and constructive control environment in which all employees understand their roles and obligations. The objectives, policies and processes for managing risk were consistent with those in the prior year.

Market Risk

Market risk is the risk that changes in market prices (interest rates) will affect the Partnership's income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Partnership's Bonds are subject to a fixed interest rate of 6.6% per annum, payable semi-annually on June 16 and December 16. As a result of having fixed rate debt, fluctuations in market interest rates are not expected to materially affect the Partnership's cash flows.

Credit Risk

Credit risk is the risk of financial loss to the Partnership if a counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Partnership's receivables from counterparties. The carrying amount of financial assets represents the maximum credit exposure.

The Partnership actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

The majority of trade receivable transactions entered by the Partnership are with the Independent Electricity System Operator ("IESO"). The IESO operates the provincial transmission system, and is a reliable counterparty. The quality of the Partnership's counterparties mitigates the Partnership's exposure to credit risk.

(expressed in thousands of Canadian dollars)

19. FINANCIAL INSTRUMENTS (continued)

The Partnership's maximum exposure to credit risk as at December 31 is as follows:

	December 31, 2014	December 31, 2013
Trade and other receivables	$ 3,422	$ 3,476

The Partnership is also exposed to credit risk on cash. Credit risk is mitigated by ensuring the majority of the financial assets are placed with a major Canadian financial institution with strong investment-grade ratings by a primary ratings agency. The credit risk of cash has been assessed as low.

Liquidity Risk

Liquidity risk is the risk that the Partnership will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset. The Partnership manages liquidity risk by forecasting cash flows required by operations and anticipating investing and financing activities to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they are due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Partnership's reputation.

The table below analyzes the Partnership's financial liabilities into relevant maturity groupings based on the remaining period at the date of the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows:

		Contractual Maturities				
	Carrying Amount	Less Than 1 Year	1-2 Years	3-5 Years	More Than 5 Years	Total
Trade and other payables	$ 3,223	$ 3,223	$ -	$ -	$ -	$ 3,223
Trans senior bonds	114,923	9,866	9,866	29,598	127,574	176,904
	$118,146	$13,089	$9,866	$29,598	$127,574	$180,127

At year end, the Partnership's relatively stable operating cash flows provide sufficient liquidity to fund these contractual obligations.

20. RELATED PARTY TRANSACTIONS AND BALANCES

Through the normal course of business, the Partnership enters into transactions with parties that meet the definition of a related party. Throughout the year ended December 31, 2014 the Partnership entered into the following transactions with entities considered to be related:

(a) In the normal course of operations, Riskcorp Inc., an insurance broker related through common control, entered into transactions with the Partnership to provide insurance. The total cost allocated to the Partnership in 2014 was $373 (2013 - $319) and no amount remains outstanding at year end.

(b) The Partnership has provided services to and received services from entities under common control in the normal course of operations. The balances payable and receivable for these services are non-interest bearing and unsecured. The balances payable to and receivable from related parties will come due during the following year.

Office Complex

The office complex in which the Partnership conducts its operations is owned by GLPL, and leased by the Partnership. Lease payments are made to GLPL on a monthly basis, with the annual lease cost for 2014 equal to $334 (2013 - $331).

Communication Equipment

The Partnership uses various types of communication assets including Supervisory Control and Data Acquisition ("SCADA") equipment, and a fiber optic network. The communication equipment is owned by GLPL and is licensed by the Partnership. License fee payments are made to GLPL on a quarterly basis, with the annual lease cost for 2014 equal to $166 (2013 – $377). Effective Q3 2013, the Partnership owns and operates a stand-alone SCADA system.

The Partnership owns Radio Systems Assets and issues licenses for the use of these assets to GLPL. License fee payments are received from GLPL on a quarterly basis, with the annual lease payments for 2014 equal to $37 (2013 - $35).

Pole Rental

The Partnership owns transmission poles and receives license fee payments in accordance with a Licensed Attachment Agreement between the Partnership and GLPL. This agreement allows GLPL to affix and maintain its apparatus and equipment to the transmission poles owned by the Partnership. Payments are received by the Partnership annually. Total payments received by the Partnership in 2014 are equal to $33 (2013 - $33).

Road Maintenance

The Partnership shares a remote roadway in the northern portion of its service territory with GLPL. The roadway is used for access to various generating stations and transmission stations. The road maintenance costs are shared between the Partnership and GLPL, with GLPL incurring the initial cost and passing a predetermined portion on to the Partnership. Payments for this road maintenance are made to GLPL as the costs are incurred by GLPL, with the total portion borne by the Partnership in 2014 being equal to $136 (2013 - $92).

(expressed in thousands of Canadian dollars)

20. RELATED PARTY TRANSACTIONS AND BALANCES (continued)

Corporate Costs

In accordance with the Services Agreement between BIH and the Partnership in effect January 1, 2012 until January 1, 2017, the Partnership records a corporate cost allocation for services received. The Partnership may request such services as but not limited to information technology management, human resource administration, and financial administration. The total corporate cost allocation recorded as an expense in 2014 was $400 (2013 - $400).

(c) As a result, the following balances are receivable (payable) as at:

	Dec 31, 2014	Dec 31, 2013
Due from related parties		
Services provided to entities under common control	$ 89	$ 36
Due to related parties		
Services received from entities under common control	$ 218	$ 585

(d) Transactions with key management personnel

A summary of key management and director compensation for the year ended December 31 is as follows:

	2014	2013
Salaries, management bonus and fees	$ 881	$ 808
Other benefits	129	245
Director fees	15	15
	$ 1,025	$ 1,068

IMPACT OF THE PROPOSED TRANSACTION

1.0 INTRODUCTION

This Exhibit provides HOI's impact assessment of the proposed transaction. The assessment is organized into two parts. Section 2 provides a discussion of GLPT's and Hydro One's expected future operations. Section 3 addresses all elements of the Board's "no harm" test.

2.0 DISCUSSION OF GLPT AND HYDRO ONE'S FUTURE OPERATIONS

After the transaction closes, GLPT and Hydro One will continue to operate as stand-alone licensed transmitters. Continuity of GLPT's operational management team is expected following the close of the transaction. Existing GLPTLP debt covenants prevent GLPT from being amalgamated absent consent of the debt holders and potential renegotiations of the fundamental terms of the GLPTLP debt instruments. Renegotiation of these terms is expected to result in the incurrence of substantial costs. As such, HOI intends to allow GLPT's outstanding debt obligations to reach maturity in mid-2023. Formal amalgamation steps will be considered after this time.

Commencing in 2017 and 2018, GLPT and Hydro One will begin to identify areas where longer term operational synergies and savings may be achieved. HOI does not expect any significant operational integration steps to occur during these years. Realized savings would therefore be achieved in 2019 and beyond. Potential areas of synergy savings include reviewing/defining the long term transmission needs for the entire East Lake Superior regional planning area through consolidated planning, assessing future investment needs in the area, and efficiently planning expenditures to realize savings while maintaining a safe and reliable transmission system. These efforts will include coordination with customers, other transmitters, distributors and the IESO regarding future infrastructure planning. Hydro One and GLPT will incorporate these consultations into their future transmission plans.

3.0 CONSIDERATION OF RELEVANT STATUTORY OBJECTIVES

The "no harm" test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB's statutory objectives, as set out in section 1 of the Act. In accordance with section 2.2.4 of the Board's *Filing Requirements for Consolidated Applications*, evidence to demonstrate the impact of the proposed transaction with respect to the OEB's first two statutory objectives is provided below.

Promote Economic Efficiency and Cost Effectiveness

HOI has assumed that the proposed 10 year rebasing deferral period will remain in effect from 2017 until 2026 inclusively. GLPT's proposed 2017/18 rate application will be the basis for its revenue requirement for 2017 and 2018 subject to Board approval. The most substantive change resulting from the transaction in this period is the substitution of HOI for BIH as GLPT's parent company. GLPT's applied-for revenue requirement will not be affected by this change in ownership.

Commencing January 1, 2019, HOI proposes using GLPT's 2018 approved revenue requirement, adjusted for inflation, for the purpose of calculating 2019 Uniform Transmission Rates ("UTR"). The revenue requirement in each subsequent year of the rebasing deferral period will be calculated in the same manner; namely taking the prior year's approved revenue requirement and adjusting this amount for inflation (see **Exhibit A, Tab 3, Schedule 1** for more details). This proposed rate methodology would be implemented by GLPT filing a Draft Rate Order for Board approval in the fall of 2018 and in the fall of each subsequent year during the balance of the rebasing deferral period. The Draft Rate Order filing will set out the determinants used in the revenue requirement calculation.

In years 6 through 10 of the rebasing deferral period, an earning sharing mechanism ("ESM") will take effect. The ESM is described in **Exhibit A, Tab 1, Schedule 1, Part 5** and **Exhibit A, Tab 3, Schedule 1**. The purpose of the ESM is to protect customers and "ensure that they share in any increased benefits from consolidation during the deferred rebasing period"[1].

The transaction is expected to result in downward pressure on the cost structures of Hydro One and GLPT as compared to the scenario where the transaction did not proceed. This conclusion is supported by two comparative assessments: (1) Hydro One and GLPT's productivity improvements; and (2) savings opportunities relative to the status quo scenario.

Forecast Productivity Improvements

The productivity of individual transmitters is generally measured by "OM&A per gross fixed assets". GLPT's 2015 actual OM&A to gross fixed asset ratio is approximately 3.0%. Comparatively, Hydro One Transmission's actual 2015 OM&A to gross fixed asset ratio is 2.9%.

Table 1 below provides the actual results for the last five years on this measure for the two entities.

TABLE 1 – TRANSMITTER PRODUCTIVITY COMPARISON

Actual OM&A/ GFA	2011	2012	2013	2014	2015
HONI	3.5%	3.1%	2.7%	2.8%	2.9%
GLPT	3.1%	2.8%	3.1%	3.0%	3.0%

The productivity factor measurements suggest that the two companies have comparable ratios and no harm to productivity should result from the transaction.

Year over Year Comparative Cost Structure Analysis for the Transaction

[1] Handbook to Electricity Distributor and Transmitter Consolidations, page 16

In compliance with the Filing Requirements, information is provided pertaining to GLPT's assumed future cost structures using "without transaction" and "with transaction" assumptions.

Table 2 provides GLPT's "without transaction" forecast of capital expenditures. The amounts shown are based on HOI's review of GLPT's draft capital expenditure plan.[2]

TABLE 2 –GLPT CAPITAL EXPENDITURE FORECAST WITHOUT TRANSACTION

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	19.4	16.2	17.6	18.6	17.5	20.6	19.9	18.3	17.4	17.8

Capital expenditure reductions arising from the transaction are expected to result from some asset redundancy, the economic scale of Hydro One's operations, and potential savings from adopting Hydro One's asset management programs. The level of actual realized savings is uncertain and will depend on the experience gained by the parties in 2017 and 2018, circumstances prevailing when operational integration plans are implemented, as well as external factors affecting operations (e.g. storms). In order to reflect this uncertainty, Hydro One has developed two "with transaction" capital forecast scenarios.

Scenario Descriptions

The first scenario is referred to as the Base Case. This scenario assumes that synergy savings occur in years 3 to 5 and relate to cost reductions associated with the SCADA system, transport and work equipment, spare parts inventory, and asset replacement costs. In years 6 and 7, costs attributable to the relocation of a backup control centre are expected to be avoided given Hydro One's existing infrastructure. Additional cost savings are assumed in years 3 through 10 due to GLPT's use of other Hydro One operational programs, such as its Asset Risk Assessment model. Barring unforeseen circumstances, the estimated savings shown in the Base Case are attainable and may potentially be exceeded.

[2] GLPT's Transmission System Plan will be filed with its 2017/18 Cost of Service application later this year

The second scenario is referred to as the High Case. The assumptions made in this Case are the same as the Base Case, but capital expenditures are assumed to be reduced by an additional 10% in years 3 to 10. These savings could arise from IT system scale optimization (e.g. telecommunications, HR, financial etc.), the avoidance of significant costs for improvements to redundant buildings and facilities, and strengthening purchasing economies of scale.

Table 3 below provides the results of the Base and High capital savings analysis.

TABLE 3–CAPITAL EXPENDITURE FORECAST WITH TRANSACTION SHOWING BASE AND HIGH POTENTIAL COST SCENARIOS

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base	19.4	16.2	14.7	14.1	15.3	17.6	16.9	17.8	16.9	17.3
High	19.4	16.2	13.2	12.7	13.8	15.8	15.2	16.0	15.2	15.6

OM&A Comparative Cost Forecast

Operating, maintenance and administrative ("OM&A") cost forecast information for the "without transaction" and "with transaction" assumptions is presented in this section.

Table 4 below provides a forecast of GLPT's average annual OM&A costs estimated for each year of the rebasing deferral period. The forecast is based on GLPT's 2017 and 2018 forecast and adjusted for inflation for the subsequent years.

TABLE 4 –GLPT OM&A COST FORECAST WITHOUT TRANSACTION

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OM&A	11.5	11.7	11.9	12.2	12.4	12.7	12.9	13.2	13.4	13.7

Similar to the Capital Expenditures assessment, the "with transaction" OM&A forecast has been developed using the assumption that GLPT will continue to operate on a stand-alone basis during 2017 and 2018. After 2018, the areas in which OM&A savings are expected relate to scale and operational synergies. These include procurement, maintenance programs, planning, operations, project management, engineering, scheduling, back-office administration, corporate governance, etc. Additional areas of savings opportunities may include information technology, insurance and research and development. Optimization of these functions may contribute to the overall efficiency benefits associated with this Transaction. Given the uncertainties associated with developing a 10 year savings forecast, HOI has prepared two case scenarios.

OM&A Case Scenarios

The first OM&A scenario is referred to as the Base Case. This scenario assumes that a 10% cost savings level on GLPT's "without transaction" costs is achieved in years 3 to 10 of the rebasing deferral period. In years 8 through 10 an additional $500,000 of achieved savings is assumed to reflect the legal and financial amalgamation of the two entities which is expected to occur in that timeframe. No incremental cost savings are expected in 2017 and 2018 given the assumption that GLPT operates as a stand-alone entity in this timeframe, akin to a "without transaction" scenario. Barring any unforeseen circumstances, the estimated savings presented in the Base Case are attainable and may potentially be exceeded.

The second OM&A scenario is referred to as the High Case. The assumptions made in this Case are the same as the Base Case with the exception that achieved cost savings in each of years 3 through 10 reach a 30% level on GLTP's "without transaction" costs. The High Case illustrates the magnitude of potential savings if greater operational integration cost efficiencies are achieved in the identified areas.

OM&A Sensitivity Analysis Results

Table 5 below provides the results of the OM&A sensitivity analysis.

TABLE 5 –OM&A COST FORECAST WITH TRANSACTION SHOWING BASE AND HIGH POTENTIAL COST SCENARIOS

$/Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base	11.5	11.7	10.7	11.0	11.2	11.4	11.6	11.4	11.6	11.8
High	11.5	11.7	8.3	8.5	8.7	8.9	9.0	8.7	8.9	9.1

Qualitative Benefits

Qualitative benefits associated with the transaction include the following:

- Coordinated regional planning, emergency response and ongoing outage management activities are expected to create benefits;
- Opportunities for GLPT's management and staff to work within the Hydro One organization. These resources will help address expected retirements and other attrition;
- The coordination of Hydro One and GLPT's existing staff is expected to improve regional system knowledge and allow for the implementation of best in class programs.

Incremental Transaction Costs

Incremental transaction costs include costs for items such as data and other IT Systems integration, regulatory approvals and legal advice. These types of costs will be financed through productivity gains associated with the transaction and will not be included in either GLPT or Hydro One's revenue requirement and thus will not be funded by ratepayers. These costs are expected to be incurred during the deferred rebasing period, and will therefore be offset through the productivity gains achieved during this time period.

Share Valuation and Financing of the Proposed Transaction

Valuation of the Transaction was the result of a multiple party competitive bid process undertaken by BIH and BIP.

HOI is not financing the Transaction with new debt sources. Instead, the purchase price will be paid in cash through use of existing credit facilities and the assumption of GLPL's existing debt.

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. As indicated in **Exhibit A, Tab 1, Schedule 1**, the value of the Transaction equates to approximately 2% of HOI's fixed assets. In alignment with Board practice and as referred to in the Handbook, the premium paid over the net book value of the assets will not be recovered through revenue requirement and no return will be earned on that premium.

Protection of Consumers with Respect to Prices and the Adequacy, Reliability and Quality of Electricity Services

Price of Electricity Service

The OEB approves the revenue requirements of transmitters in Ontario. GLPT currently accounts for approximately 2.6% of the uniform rates and revenue allocators. Hydro One represents approximately 94.6% of these rates and allocators. The OEB also approves the charge determinants of individual transmitters and uses these to calculate the UTR. The current approved UTRs for 2016 are: Network Service Rate \$3.66/kW, Line Connection Service Rate \$0.87/kW, Transformation Connection Service Rate \$2.02/kW.

The UTR impact of the transaction at the end of the 10 year rate rebasing deferral period (relative to a "without transaction" scenario) is forecast to be an approximate \$0.01 reduction to the Network Service Rate under the Base Case scenarios (i.e. capital and OM&A). Under the

High Case scenarios, the Network Service Rate is forecast to decline by approximately $0.02, and additionally $0.01 reductions are expected to both the Line Connection and Transformation Connection Service Rates.

Adequacy, Reliability and Quality of Electricity Service

Hydro One does not expect that the reliability of either transmission system will be materially impacted as a result of the transaction. Hydro One and GLPT are both experienced licensed transmitters. All licensed transmitters in the province are required to meet standardized performance expectations and public policy objectives relating to reliability. Both Hydro One and GLPT must design and operate their respective systems in conformance with the IESO Market Rules and the Ontario Resource & Transmission Assessment Criteria ("ORTAC"). Both systems must also comply with reliability standards established by NERC. Given that the system topology of Hydro One and GLPT will not be changing and both utilities adhere to the same design and operating standards required by all transmitters in the IESO-controlled grid, Hydro One and GLPT are confident that reliability will not be impacted.

Please see **Table 6** below for a comparison of Hydro One's regional reliability indices against those of GLPT.

TABLE 6 – RELIABILITY INDICES REGIONALLY OF HYDRO ONE AND GLPT

	2010	2011	2012	2013	2014	2015
HONI - SAIDI[3]	28.1	39.6	75.9	184.3	40.7	66.1
GLPT - SAIDI	150.7	296.7	176.8	861.1	25.4	79.8
HONI - SAIFI	0.76	0.50	0.86	0.97	2.23	0.81
GLPT - SAIFI	1.33	2.14	2.24	1.37	0.47	0.89

[3] Hydro One's SAIDI and SAIFI results in Table 7 are premised on the results of the Mississagi TS to Martindale TS subsystem. This segment of Hydro One's transmission system is similarly situated, sized (in terms of asset types, line length, and delivery points) and carries a comparable load to that of GLPT.

Table 6 depicts that the reliability results of the two similarly situated systems indicate that over the last 5 years, Hydro One's reliability measures in most years are better that GLPT. Hydro One does not believe that that this transaction will have any negative impact on this reliability or its trend, and believes that, once best practices of both organizations are amalgamated, these metrics could further improve.

SELECTED RATE REBASING DEFERRAL PERIOD

This Exhibit provides additional information concerning GLPT's selected rate rebasing deferral period and the methodology HOI on behalf of GLPT will seek to use to calculate its annual revenue requirement during the deferral period.

1.0 SELECTED RATE REBASING DEFERRAL PERIOD

The selected rate rebasing deferral period will give HOI and GLPT the opportunity to achieve operational and synergy savings, reducing utility cost structures and creating a more efficient transmission system. Cost savings achieved during the deferral period will be used to offset transaction costs and premiums. Once the rebasing period has concluded, achieved reductions in the utility cost structures will be reflected in the rebased rates charged to customers.

2.0 GLPT REVENUE REQUIREMENTS DURING REBASING DEFERRAL PERIOD

In 2016, GLPT intends to file a rate application for approval of its 2017 and 2018 revenue requirements. For 2019 and each subsequent year of the rebasing deferral period, GLPT will calculate the annual revenue requirement by using GLPT's prior year revenue requirement and adjusting this amount with an inflation factor.

2.1 Inflation Factor

The proposed inflation factor used during the rebasing deferral period would align with the calculation described in Chapter 3 of the *Distribution Filing Requirements*. HOI proposes having the productivity and stretch factor set at 0%, given that the circumstances in this case concern transmission entities and that the OEB does not have any established revenue adjustment mechanisms in place for transmission and that achieved savings realized in the deferred rebasing period are intended for the acquiring utility shareholder's benefit to offset transaction costs and premiums. Inclusion of a productivity and stretch factor would reduce the annual revenue requirement, and thereby reduce the amounts of achieved cost savings available to the acquiring utility, savings which would have only resulted due to the transaction proceeding. Consolidating entities are highly incented, through the Board's MAAD policies, to implement productivity improvements during the rebasing deferral period. Ratepayers are protected and will share in any increased benefits from the consolidation during the rebasing deferral period through the implementation of an earnings sharing mechanism. Long-term operational efficiencies and reduced cost structures resulting from the transaction will also be reflected in rates upon completion of the rebasing deferral period, again to the benefit of ratepayers.

2.2 Earnings Sharing Mechanism

The proposed earnings sharing mechanism will take effect during the last five years of the rebasing deferral period. GLPT's revenue requirement will be adjusted so that prior year excess earnings are shared with ratepayers on a 50:50 basis for all earnings that exceed 300 basis points above the return on equity approved by the Board for 2018 in GLPT's 2017-18 rates application.

Implementation of a formal amalgamation of GLPT and Hydro One is not expected to occur before mid-2023. This timing is in part due to covenant restrictions found in GLPTLP's existing debt obligations. Renegotiation of these obligations cannot occur without substantial penalties. Until amalgamation occurs, GLPT will operate as a stand-alone entity and segmented reporting and audited financial statements will be available. GLPT's audited financial statements will be used to calculate any earning sharing amounts if amalgamation has not occurred during the rebasing deferral period. If the achieved regulatory ROE (excluding one-time extraordinary, unusual items and any OEB-approved adjustments) is 300 basis points above the deemed regulatory ROE, GLPT will share the overearnings on a 50:50 basis. Any shared amount will be treated as a reduction in a subsequent year revenue requirement calculation.

If amalgamation proceeds during the rebasing deferral period, separate audited financial statements for GLPT will not be available. The production of separate financial statements for the former GLPT entity may not be practicable and would reduce synergies arising from integrating the operations of GLPT with Hydro One's. It is nonetheless HOI's intention to share any potential overearnings on a 50:50 basis in a fair and practical manner. In the absence of audited financial statements, GLPT's last available audited financial statement will serve as a proxy for the achieved ROE amount (excluding one-time extraordinary, unusual items and any OEB-approved adjustments) for purposes of calculating shared earnings. If the achieved ROE amount is greater than 300 basis points over the Board-approved ROE, the overearnings will be shared, and the shared amount will be held constant and treated as an annual credit to each subsequent revenue requirement amount in the remaining rebasing deferral period. As above, any shared amount will be treated as a reduction in a subsequent year revenue requirement calculation.

Hydro One believes that this ESM is in line with the Board's Handbook in that it achieves the objective of protecting customer interests during the deferred rebasing period and in this situation, where audited statements will be available, allows an ESM calculation based on those financial statements.