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**Frank D'Andrea**
Vice President
Regulatory Affairs

BY COURIER

August 28, 2017

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

Dear Ms. Walli,

**EB-2017-0051 - Hydro One Remote Communities Inc. 2018 Revenue Requirement and Rates Application – Application and Prefiled Evidence**

The Hydro One Remote Communities' application and supporting evidence seeking approval of the 2018 revenue requirement and customer rates for the distribution and generation of electricity to be implemented on May 1, 2018, have been submitted using the Ontario Energy Board's Regulatory Electronic Submission System. The application and supporting evidence will be made available on the Hydro One's Regulatory Affairs web page:

https://www.hydroone.com/abouthydroone/RegulatoryInformation/remotecommunities

In addition, a copy of the application and evidence is being provided for public access at Hydro One Remote Communities' Service Centre, located at 680 Beaverhall Place, Thunder Bay, P7E 6G9.

Hydro One Remote Communities' points of contact for service of documents associated with this Application are listed in Exhibit A, Tab 2, Schedule 1.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Encl.

# EXHIBIT LIST

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**ONTARIO ENERGY BOARD**

IN THE MATTER OF *the Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Hydro One Remote Communities Inc. for an Order or Orders approving rates for the distribution of electricity.

# APPLICATION

## THE APPLICANT AND ORDERS REQUESTED

1. The Applicant is Hydro One Remote Communities Inc., a subsidiary of Hydro One Inc. The Applicant, which will hereinafter be referred to as "Remotes", is an Ontario corporation with its head office in Toronto. The Applicant is an integrated generation and distribution company licensed to generate and distribute electricity within 21 isolated communities in northern Ontario. The applicant is not a host or embedded distributor.

2. Remotes hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 78 of the Ontario Energy Board Act, 1998, for an Order or Orders approving its proposed 2018 revenue requirement and customer rates for the distribution and generation of electricity. Remotes requests that the hearing be heard by way of a written hearing.

3. Remotes seeks approval of a revenue requirement of $56,689K for the Test Year 2018, of which $17,612K is proposed to be recovered through customer rates and

$999K from other revenues, leaving $38,078K to be recovered from Rural and Remote Rate Protection (RRRP).

4. Remotes seeks approval to dispose of the 2016 audited balance in the RRRP Variance Account, less a 2017 adjustment for taxes, as described in Exhibit H1, Tab 1, Schedule 1.

5. Remotes seeks approval to continue the RRRP Variance Account as described in Exhibit G1, Tab 4, Schedule 1

6. Remotes seeks approval of a 1.8% increase to customer rates as identified in the proposed Tariff of Rates and Charges in Exhibit G2, Tab 3, Schedule 2, to be effective May 1, 2018.

7. Remotes is not seeking any changes whatever to specific services charges. Rather, Remotes seeks approval to continue to charge customers the same specific service charges identified in the proposed Tariff of Rates and Charges in Exhibit G2, Tab 3, Schedule 2, to be effective May 1, 2018.

8. Remotes is a unique distributor in Ontario and is exempt from a number of the legal and regulatory requirements imposed on most distributors. Remotes generates electricity at diesel generating stations in certain isolated communities in the far north and distributes the electricity to customers in each community. As such, Remotes is neither an embedded distributor nor a host distributor.

9. The written evidence filed with the Board may be amended from time to time prior to the Board's final decision on the Application. Further, the Applicant may seek

meetings with Board staff and intervenors in an attempt to identify and reach agreements to settle issues arising out of this Application.

10. The persons affected by this Application are the ratepayers of Remotes and of RRRP. It is impractical to set out their names and addresses because they are too numerous.

11. Electricity distribution rates as identified in the proposed Tariff of Rates and Charges in Exhibit G2, Tab 3, Schedule 2 to be effective May 1, 2018. These rates are calculated to support Remotes' 2018 base revenue requirement.

12. To reach the largest number of customers in its service territory, Remotes requests that notice of this Application be published on the Wawatay website in English, Cree, Oji Cree and Ojibway, the Thunder Bay Chronicle Journal and the Sudbury Star.

13. There are no rates and charges linked in the Conditions of Service that are not in Remotes' Tariff of Rates and Charges. The current Conditions of Service can be found on Hydro One's website at:

https://www.hydroone.com/abouthydroone/RegulatoryInformation/remotecommunities

14. Remotes requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

a) The Applicant:

Ms Eryn MacKinnon
Sr. Regulatory Coordinator - Regulatory Affairs
Hydro One Networks Inc.

Address for personal service: 8th Floor, South Tower
483 Bay Street

Toronto, ON M5G 2P5

Mailing Address: 8th Floor, South Tower
483 Bay Street
Toronto, ON M5G 2P5

Telephone: (416) 345-4444
Fax: (416) 345-5866
E-mail: Regulatory@HydroOne.com

b) The Applicant's counsel:

Mr. Michael Engelberg
Assistant General Counsel
Hydro One Networks Inc.

Mailing Address: 8th Floor, South Tower
483 Bay Street
Toronto, ON M5G 2P5

Telephone: (416) 345-6305
Fax: (416) 345-6972
E-mail: mengelberg@HydroOne.com

DATED at Toronto, Ontario, this 28th day of August, 2017.

HYDRO ONE REMOTE COMMUNITIES INC.

By its counsel,

_________________________________

Michael Engelberg

# CERTIFICATION OF EVIDENCE

TO: ONTARIO ENERGY BOARD

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The undersigned, being Hydro One Remote Communities Inc. Managing Director, Kraemer Coulter hereby certifies for and on behalf of Hydro One Remote Communities Inc. that:

1. I am a senior officer of Hydro One Remote Communities Inc.;
2. This certificate is given pursuant to the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (last revised on July 14, 2016); and
3. The evidence submitted in support of Hydro One Remote Communities Inc. 2018 distribution application (EB-2017-0051) filed with the OEB is accurate, consistent and complete to the best of my knowledge.

DATED this 28th day of August, 2017.

KRAEMER COULTER

# COMPLIANCE WITH LICENCE AND OEB FILING REQUIREMENTS FOR ELECTRICITY DISTRIBUTORS

## 1.0 INTRODUCTION

This Application by Remotes is substantially consistent with the requirements of the 2016 Electricity Distribution Rate Handbook ("the Handbook") issued by the Board on October 13, 2016, and with the Filing Requirements for Transmission and Distribution Applications (the "Filing Requirements") issued by the Board on November 14, 2006 and updated on July 20, 2016.

Hydro One Remotes Distribution Application follows and incorporates improvements made to the filing format. Remotes' Application satisfies the Filing Requirements and Handbook requirements except where it was not practical or appropriate to do so based on previous comments and direction from the Board, or as a result of specific government regulation.

### 1.1 Compliance with Licence

<u>Exemptions from the Electricity Act, 1998</u>

Remote is exempt from the following sections of the *Electricity Act, 1998*:

- Subsection 26(1), non-discriminatory access
- Subsection 26(3), to the extent that a contract entered into by Ontario Hydro contains liabilities, rights or obligations that have been transferred to Remotes
- Section 28, distributor's obligation to connect.

Exemptions from the *Ontario Energy Board Act, 1998*

Remotes is exempt from the following sections of the *Ontario Energy Board Act, 1998*:

- Section 70(2)(e), specifying methods or techniques to be applied in determining the licensee's rates
- Section 71, restriction on business activity
- Section 80, prohibition, generation by transmitters or distributors
- Section 81, prohibition, transmission or distribution by generators

None of Remotes' customers is prescribed under Sections 79.16 under the *Ontario Energy Board Act, 1998*.

Exemptions from Licence Conditions

Remotes is exempt from the entire Standard Supply Service Code and the entire Retail Settlement Code, and from various sections of the Distribution System Code per Schedule 3 of its Distribution Licence ED-2003-0037 filed at Exhibit A, Tab 2, Schedule 2, Attachment 1.

Conservation & Demand Management Code for Electricity Distributors

Remotes is not subject to the Conservation & Demand Management Code for Electricity Distributors and has not been assigned targets under that Code.

## 2.0 COMPLIANCE WITH LICENCE AND OEB FILING REQUIREMENTS

Most of Remotes' customers are eligible for Remote Rate Protection under Section 79 of the *Ontario Energy Board Act, 1998*. O. Reg. 442/01 under that statute requires the

Board to calculate Rate Protection for these customers. This legislation requires that Remotes charge rates that are not based on the cost of service. In view of this legislative requirement, Remotes did not undertake a cost allocation study as required by Board guidelines prior to filing this application. A cost allocation study requires substantial effort and would have provided no benefit, as customers cannot be charged the cost of supplying power to them without changes to the legislation.

Remotes provides both generation and distribution services outside of the competitive market. Its rates and revenue requirement include both of these cost categories. Accordingly, information on all of Remotes' activities is included to ensure that generation and distribution costs can be examined in this proceeding.

Remotes has not provided a PEG Benchmarking Exhibit in this filing. Remotes is an integrated generation company with unique financing and operations. The Board has previously recognized that Remotes is not directly comparable to other Ontario distributors. In its Decision in proceeding EB-2014-0084, the Board noted that, "Hydro One Remotes is excluded from the Board's benchmarking analysis because of its unique circumstances. As noted in Hydro One Remotes' 2014 Price Cap Incentive Rate application (proceeding EB-2013-0142), Hydro One Remotes is unique in terms of its operating characteristics and cost recovery due to the Rural or Remote Electricity Rate Protection."

The filing requirements indicate that a forward test-year methodology is to be utilized when a distributor is seeking the Board's approval for rebasing its rates. Remotes' Application has been filed using a forward test year and provides three years of historical data. As such, this Application includes written evidence and supporting schedules for the following:

- 2018 test year;
- 2017 bridge year;
- 2013, 2014, 2015 and 2016 historical years;
- 2013 Board-approved historical year.

## 3.0 DISTRIBUTION SYSTEM PLAN

Remotes contracted with METSCO to assist with the development of a Distribution System Plan ("DSP"). METSCO is a company with experience assisting Distributors in developing these plans to meet OEB requirements. The DSP can be found at Exhibit B1.

## 4.0 RATE BASE

The Filing Requirements, past direction from the Board, and a number of specific government regulations influence the determination of Remotes' rate base and associated capital costs, as well as influencing the rate base information provided in the Application.

### 4.1 Depreciation Rates and Amortization

Remotes 2013 Revenue Requirement includes the depreciation and amortization rates based on a depreciation study conducted in 2011 by Foster Associates that was accepted by the Board and intervenors in EB-2012-0137.

Remotes recognizes a liability for estimated future expenditures required to remediate past environmental contamination associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. Since these expenditures are expected to be recoverable in future rates, Remotes has recognized an equivalent amount as a regulatory asset. This balance is amortized on a basis consistent with the pattern of actual expenditures expected to be incurred each year. Expenditures related to this remediation are discussed in Exhibit D1, Tab 6, Schedule 1.

### 4.2 Working Capital Allowance

Remotes' calculation for working capital is consistent with the default allowance as set out in the 2017 Filing Requirements and is shown in Exhibit C1, Schedule 1, Tab 1.

### 4.3 Interest Rates for Construction Work in Progress

The interest rate used for construction work in progress ("CWIP") reflects the adoption of United States generally accepted accounting principles ("US GAAP") per the Board's decision in EB-2011-0427. Under US GAAP, a utility capitalizes interest on qualifying capital programs and projects using its effective rate of its outstanding debt used to finance the capital expenditures made, unless the regulator requires the use of a specific allowance for funds used during construction rate ("AFUDC"). Consistent with its decisions in EB-2008-0408, effective January 1, 2012, no AFUDC is specified for use by Remotes. The construction work in progress evidence for the historical years, bridge year, and test year is filed in Exhibit C2, Tab 4, Schedule 3.

### 4.4 Capital Projects and Programs

Details for all capital projects and programs that exceed $283K in net capital costs (0.5% of revenue requirement) are provided in Investment Summary Documents ("ISD"s). The ISDs for these projects and programs are filed at Exhibit B1, Tab 1, Schedule 1, Appendix A.

### 4.5 In-Service Additions

Remotes continues to plan, manage and perform its internal and external reporting on a work basis using its general ledger accounts, as these are reflective of the way in which Remotes manages its operations. A schedule showing in-service additions by OEB-specified USofA accounts for 2018 test year, 2017 bridge year and 2013- 2016 historical years is filed in Exhibit C2, Tab 6, Schedule 1.

## 5.0 COST OF CAPITAL

Remotes' cost of capital is based on a 100% debt financing structure, consistent with the Board's Decision in RP-1999-001. As Remotes operates as a break-even company, it does not plan to seek a return on capital.

## 6.0 OPERATING (OM&A) COST OF SERVICE

Remotes' OM&A evidence has been filed on a USofA basis. Information for the 2018 test year, 2017 bridge year, and 2013-2016 historical years is filed at Exhibit D2, Tab 2, Schedule 1.

## 7.0 OPERATING REVENUE AND REVENUE SUFFICIENCY/DEFICIENCY

The revenue sufficiency/deficiency for 2018 Remotes is shown in Exhibit F and through the calculation of the annual RRRP, in Exhibit G1, Tab 4, Schedule 1.

# Electricity Distribution Licence

# ED-2003-0037

# Hydro One Remote Communities Inc.

**Valid Until**

**December 23, 2023**

*Original signed by*

**Brian Hewson**
**Vice President, Consumer Protection and Industry Performance**
**Ontario Energy Board**

**Date of Issuance: December 24, 2003**
**Date of Amendment: March 31, 2017**


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

## LIST OF AMENDMENTS

| Board File No. | Date of Amendment |
|---|---|
| EB- 2004-0206 | June 1, 2004 |
| EB-2009-0363: | December 16, 2009 |
| EB-2011-0021 | April 25, 2013 |
| EB-2016-0015 | January 28, 2016 |
| EB-2017-0101 | March 31, 2017 |

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## 1 Definitions

In this Licence:

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

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

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

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

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

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

"**Licensee**" means Hydro One Remote Communities Inc.

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

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

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

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

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

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

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

## 2 Interpretation

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

## 3 Authorization

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

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

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

## 4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

## 5 Obligation to Comply with Codes

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

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

b) the Distribution System Code.

5.2 The Licensee shall:

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

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

**6 Obligation to Sell Electricity**

6.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Licensee's Rate Order as approved by the Board.

**7 Obligation to Maintain System Integrity**

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

**8 Market Power Mitigation Rebates**

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

**9 Distribution Rates**

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

**10 Separation of Business Activities**

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

**11 Expansion of Distribution System**

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

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

**12 Provision of Information to the Board**

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

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

## 13 Restrictions on Provision of Information

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

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection, band council or government agency for the processing of past due accounts of the consumer or generator.

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

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

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

## 14 Customer Complaint and Dispute Resolution

14.1 The Licensee shall:

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

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

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

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

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

15 **Term of Licence**

15.1 This Licence shall take effect on December 24, 2003 and expire on December 23, 2023. The term of this Licence may be extended by the Board.

16 **Fees and Assessments**

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

17 **Communication**

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

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

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

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

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

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

18 **Copies of the Licence**

18.1 The Licensee shall:

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

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

19 **Pole Attachments**

19.1 The Licensee shall provide access to its distribution poles to all Canadian carriers, as defined by the Telecommunications Act, and to all cable companies that operate in the Province of Ontario. For each attachment, with the exception of wireless attachments, the Licensee shall charge the rate approved by the Board and included in the Licensee’s tariff.

19.2 The Licensee shall:

a) annually report the net revenue, and the calculations used to determine that net revenue, earned from allowing wireless attachments to its poles. Net revenues will be accumulated in a deferral account approved by the Board;

b) credit that net revenue against its revenue requirement subject to Board approval in rate proceedings; and

c) provide access for wireless attachments to its poles on commercial terms normally found in a competitive market.

## 20 Winter 2016/17 Disconnection, Reconnection and Load Limiter Devices

20.1 Subject to paragraph 20.4, the Licensee shall not, during the period commencing February 24, 2017 and ending at 11:59 pm on April 30, 2017:

a) disconnect an occupied residential property solely on the grounds of non-payment;

b) issue a disconnection notice in respect of an occupied residential property solely on the grounds of non-payment; or

c) install a load limiter device in respect of an occupied residential property solely on the grounds of non-payment.

Nothing in this paragraph shall preclude the Licensee from (i) disconnecting an occupied residential property in accordance with all applicable regulatory requirements, including the required disconnection notice; or (ii) installing a load limiter device in respect of an occupied residential property, in each case if at the unsolicited request of the customer given in writing on or after February 24, 2017.

20.2 Subject to paragraph 20.4, if the Licensee had disconnected a residential property on or before February 23, 2017 solely on the grounds of non-payment, the Licensee shall reconnect that property, if an occupied residential property, as soon as possible. The Licensee shall waive any reconnection charge that might otherwise apply in respect of that reconnection.

Nothing in this paragraph shall require the Licensee to reconnect an occupied residential property if the customer gives unsolicited notice to the Licensee not to do so in writing on or after February 24, 2017.

20.3 Subject to paragraph 20.4, if the Licensee had installed a load limiter device in respect of an occupied residential property on or before February 23, 2017 either for non-payment or at the customer's request, the Licensee shall remove that device and restore full service to the property as soon as possible. The Licensee shall waive any charge that might otherwise apply in respect of such removal.

Nothing in this paragraph shall: (i) require the Licensee to remove a load limiter device if the customer gives unsolicited notice to the Licensee not to do so in writing on or after February 24, 2017; or (ii) prevent the Licensee from installing or maintaining a load limiter device at the unsolicited request of customer given in writing on or after February 24, 2017.

20.4 Nothing in paragraphs 20.1 to 20.3 shall:

a) prevent the Licensee from taking such action in respect of an occupied residential property as may be required to comply with any applicable and generally acceptable safety requirements or standards; or

b) require the Licensee to act in a manner contrary to any applicable and generally accepted safety requirements or standards.

20.5 The Licensee shall waive any collection of account charge that could otherwise be charged in relation to an occupied residential property during the period referred to in paragraph 20.1.

20.6 The Licensee shall provide the Board with periodic reports on its progress in complying with paragraphs 20.2 and 20.3. The first such report shall be filed with the Board no later than March 3, 2017, and reports shall be provided every 7 calendar days thereafter until such time as no further action remains to be taken by the Licensee under those paragraphs.

20.7 For the purposes of paragraphs 20.1 to 20.4:

"load limiter device" means a device that will allow a customer to run a small number of electrical items in his or her premises at any given time, and if the customer exceeds the limit of the load limiter, then the device will interrupt the power until it is reset; and

"occupied residential property" means an account with the Licensee:

a) that falls within the residential rate classification as specified in the Licensee's Rate Order; and
b) that is:

i) inhabited; or
ii) in an uninhabited condition as a result of the property having been disconnected by the Licensee or of a load limiter device having been installed in respect of the property on or before February 23, 2017.

20.8 Paragraphs 20.1 to 20.5 apply despite any provision of the Distribution System Code to the contrary.

**SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA**

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 6.1 of this Licence.

1. Armstrong
2 Bearskin Lake
3. Big Trout Lake
4. Biscotasing
5. Collins
6. Deer Lake
7. Fort Severn
8 Gull Bay
9 Hillsport
10. Kasabonika Lake
11. Kingfisher Lake
12. Landsdowne House
13. Oba
14. Sachigo Lake
15. Sandy Lake
16. Sultan
17. Wapakeka
18. Weagamow
19. Webequie
20 Whitesand
21 Marten Falls (operated by the Licensee, owned by Marten Falls First Nation)

**SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE**

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

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 6.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

**SCHEDULE 3 LIST OF CODE EXEMPTIONS**

This Schedule specifies any specific Code requirements that are not applicable to the Licensee.

1. The entire Retail Settlement Code

2. The entire Standard Supply Service Code

3. Sections 2.7.1.2; 2.7.1.3; 2.7.2; 2.8.1; 2.8.2; 4.2.2.3; 4.2.3.1(a); 6.1.2.1; 6.1.2.2 and 7.10 of the Distribution System Code.

**APPENDIX A**

**MARKET POWER MITIGATION REBATES**

## 1. Definitions and Interpretations

In this Licence

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

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

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

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

## 2. Information Given to IESO

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

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

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

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

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

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

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

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

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

## 3. Pass Through of Rebate

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

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

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

c embedded distributors to whom the distributor distributes electricity.

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

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

“ONTARIO POWER GENERATION INC. rebate”

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

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

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

**ONTARIO POWER GENERATION INC. REBATES**

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

**1. Definitions and Interpretations**

In this Licence

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

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

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

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

**2. Information Given to IESO**

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

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

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

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

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

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

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

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

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

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

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

c embedded distributors to whom the distributor distributes electricity.

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

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

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

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

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

# Electricity Generation Licence

# EG-2003-0138

# Hydro One Remote Communities Inc.

**Valid Until**

**October 19, 2023**

*Original signed*

___________________________________

**Jennifer Lea**
**Counsel, Special Projects**
**Ontario Energy Board**
**Date of Issuance:  October 20, 2003**
**Date of Amendment:  June 1, 2004**
**Date of Amendment:  December 16, 2009**


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

**Table of Contents** **Page No.**

## 1 Definitions

In this Licence:

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

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

"**generation facility**" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system and includes any structures, equipment or other things used for that purpose;

"**Licensee**" means Hydro One Remote Communities Inc.;

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

## 2 Interpretation

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

## 3 Authorization

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

a) to generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person subject to the conditions set out in this Licence. This Licence authorizes the Licensee only in respect of those facilities set out in Schedule 1;

b) to purchase electricity or ancillary services in the IESO-administered markets or directly from a generator subject to the conditions set out in this Licence; and

c) to sell electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer, subject to the conditions set out in this Licence.

## 4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

## 5 Obligation to Maintain System Integrity

5.1 Where the IESO has identified, pursuant to the conditions of its licence and the Market Rules, that it is necessary for purposes of maintaining the reliability and security of the IESO-controlled grid, for the Licensee to provide energy or ancillary services, the IESO may require the Licensee to enter into an agreement for the supply of energy or such services.

5.2 Where an agreement is entered into in accordance with paragraph 5.1, it shall comply with the applicable provisions of the Market Rules or such other conditions as the Board may consider reasonable. The agreement shall be subject to approval by the Board prior to its implementation. Unresolved disputes relating to the terms of the Agreement, the interpretation of the Agreement, or amendment of the Agreement, may be determined by the Board.

## 6 Restrictions on Certain Business Activities

6.1 Neither the Licensee, nor an affiliate of the Licensee shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario except in accordance with section 81 of the Act.

## 7 Provision of Information to the Board

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

7.2 Without limiting the generality of paragraph 7.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee, as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

## 8 Term of Licence

8.1 This Licence shall take effect on October 20, 2003 and expire on October 19, 2023. The term of this Licence may be extended by the Board.

## 9 Fees and Assessments

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

## 10 Communication

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

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

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

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

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

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

## 11 Copies of the Licence

11.1 The Licensee shall:

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

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

**SCHEDULE 1 LIST OF LICENSED GENERATION FACILITIES**

The Licence authorizes the Licensee only in respect to the following:

1. Armstrong Generation Station, owned and operated by the Licensee at Armstrong, Ontario.

2. Bearskin Lake Generation Station, owned and operated by the Licensee at Bearskin Lake, Ontario.

3. Big Trout Lake Generation Station, owned and operated by the Licensee at Big Trout Lake, Ontario.

4. Biscotasing Generation Station, owned and operated by the Licensee at Biscotasing, Ontario.

5. Dear Lake Generation Station, owned and operated by the Licensee at Dear Lake, Ontario.

6. Fort Severn Generation Station, owned and operated by the Licensee at Fort Severn, Ontario.

7. Gull Bay Generation Station, owned and operated by the Licensee at Gull Bay, Ontario.

8. Hillsport Generation Station, owned and operated by the Licensee at Hillsport, Ontario.

9. Kasabonika Generation Station, owned and operated by the Licensee at Kasabonika Lake, Ontario.

10. Kingfisher Lake Generation Station, owned and operated by the Licensee at Kingfisher Lake, Ontario.

11. Lansdowne House Generation Station, owned and operated by the Licensee at Lansdowne House, Ontario.

12. Oba Generation Station, owned and operated by the Licensee at Oba, Ontario.

13. Sachigo Lake Generation Station, owned and operated by the Licensee at Sachigo Lake, Ontario.

14. Sandy Lake Generation Station, owned and operated by the Licensee at Sandy Lake, Ontario.

15. Sultan Generation Station, owned and operated by the Licensee at Sultan, Ontario.

16. Wapekeka Generation Station, owned and operated by the Licensee at Wapekeka, Ontario.

17 Weagamow Lake Generation Station, owned and operated by the Licensee at Weagamow Lake, Ontario.

18. Webequie Generation Station, owned and operated by the Licensee at Webequie, Ontario.

19. Deer Lake Mini Hydel Generation Station, owned and operated by the Licensee at Deer Lake, Ontario.

20. Sultan Hydel Generation Station, owned and operated by the Licensee at Sultan, Ontario.

21. Marten Falls Generation Station, operated by the Licensee at Marten Falls, Ontario.

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

**Date: August 28, 2017**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **GENERAL REQUIREMENTS** | | | |
| **Ch 1, Pg. 2** | Certification by a senior officer that the evidence filed is accurate, consistent and complete | **Yes** | Exhibit A, Tab 2, Schedule 1, Attachment 1 |
| **Ch 1, Pg. 3** | Confidential Information - Practice Direction has been followed | **N/A** | Remotes is not filing any information in confidence. |
| **7** | Chapter 2 appendices in live Microsoft Excel format; PDF and Excel copy of current tariff sheet | **Yes** | Exhibit A, Tab 2, Schedule 1, Attachment 1 |
| **8** | If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year. | **N/A** | This was not a late application. |
| **8 & 9** | Aligning rate year with fiscal year - request for proposed alignment | **N/A** | Remotes is not proposing a new alignment. |
| **10** | Text searchable and bookmarked PDF documents | **Yes** | Provided. |
| **10** | Links within Excel models not broken and models names so that they can be identified (e.g. RRWF instead of Attachment A) | **Yes** | Provided. |
| **10** | Materiality threshold; additional details beyond the threshold if necessary | **Yes** | Exhibit A, Tab 2, Schedule 3 |
| **11** | Proposal for disposition of any balances in existing DVAs for renewable generation and smart grid development, if applicable | **N/A** | Remotes has no DVAs for renewable generation or smart grid development. |
| **11** | State accounting standard(s) used in historical, bridge and test years. Provide a summary of changes to its accounting policies made since the applicant's last cost of service filing. Identify all material changes or confirm no material changes in the adoption of IFRS. Appendix 2-Y | **N/A** | In proceeding EB-2011-0427, the OEB's Decision with Reasons granted Remotes' request to use United States Generally Accepted Accounting Principles for regulatory purposes. |
| **RESS Guideline** | Two hardcopies of application sent to OEB the same day as electronic filing (p10 of RESS Guideline) | **Yes** | Provided. |

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

Filing Requirement Page # Reference

Date: August 28, 2017

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS** | | | |
| *Table of Contents* | | | |
| 12 & 13 | Table of Contents listing major sections and subsections of the application. Electronic version of application appropriately bookmarked to provide direct access to each section | Yes | Exhibit A, Tab 1, Schedule 1 |
| *Executive Summary* | | | |
| 13 | Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by the Rate Handbook including plain language information about its goals | Yes | Exhibit A, Tab 3, Schedule 1, Executive Summary and Exhibit A, Tab 3, Schedule 1, attachment 1, Requested Approvals - OEB Chapter 2, Appendix 2-A |
| *Administration* | | | |
| 13 | Primary contact information (name, address, phone, fax, email) | Yes | Exhibit A, Tab 2, Schedule 1 |
| 13 | Identification of legal (or other) representation | Yes | Exhibit A, Tab 2, Schedule 1 |
| 13 | Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers | Yes | Internet Address HydroOne.com Executive Summary |
| 13 | Statement identifying customers materially affected by the application including any change to any rate or charge and specific statement of what individual customer or customer groups would be affected by the proposed change | Yes | Exhibit A, Tab 2, Schedule 1 |
| 13 | Statement identifying where notice should be published and why | Yes | Exhibit A, Tab 2, Schedule 1 |
| 13 | Bill impacts - distribution only impacts for 750 kWh residential and 2000 kWh GS<50 (sub-total A of Tariff Schedule and Bill Impact Spreadsheet Model) to be used for notice; proposed bill impacts based on alternative consumption profiles and customer groups as appropriate given consumption patterns of a distributors customers | Yes | Exhibit G, Tab 2, Schedule 1 |
| 14 | Form of hearing requested and why | Yes | Exhibit A, Tab 2, Schedule 1 |
| 14 | Requested effective date | Yes | Exhibit A, Tab 2, Schedule 1 |
| 14 | Statement identifying all deviations from Filing Requirements; identify concerns with models or changes to models | Yes | Exhibit A, Tab 2, Schedule 2 |
| 14 | Statement identifying and describing any changes to methodologies used vs previous applications | N/A | No changes in methodology |
| 14 | Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision) | N/A | No direction was received from the OEB in previous Decisions. |
| 14 | Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor' Tariff of Rates and Charges must be provided | Yes | Exhibit A, Tab 2, Schedule 1 |
| 14 | Description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control | Yes | Exhibit A, Tab 7, Schedule 1 |
| 14 | List of approvals requested (and relevant section of legislation), including accounting orders - a PDF copy of Appendix 2-A should be provided in this section | Yes | Exhibit A, Tab 3, Schedule 1, Executive Summary and Exhibit A, Tab 3, Schedule 1, attachment 1, Requested Approvals - OEB Chapter 2, Appendix 2-A |
| *Distribution System Overview* | | | |
| 14 | Description of Service Area (including map, communities served) | Yes | Exhibit B1, Tab 1, Schedule 1, section 1.4.1 |
| 15 | Description of whether the distributor is a host distributor and/or embedded distributor. Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor. If the distributor is a host, the applicant should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes such as GS > 50 kW | Yes | Exhibit A1, Tab 2, Schedule 1, Legal Form of Application |
| 15 | Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the OEB as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application | Yes | Exhibit C 1, Tab 1, Schedule 3 |
| *Application Summary* | | | |
| At a minimum, the items below must be provided. Applicants must also identify all proposed changes that will have a material impact on customers. | | | |
| 15 | Revenue Requirement - service RR, increase/decrease ($ and %) from change from previously approved and main drivers | Yes | Exhibit A, Tab 3, Schedule 1 and Exhibit G1, Tab 1 , Schedule 1 |
| 15 | Budgeting and Accounting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards | Yes | Exhibit A, Tab 3, Schedule 1 and Exhibit A, Tab 7, Schedule 3 |
| 16 | Load Forecast Summary - load and customer growth, % change in kWh/kW and customer numbers,description of forecasting method(s) used for customer/connection and consumption/demand | Yes | Exhibit A, Tab 3, Schedule 1 |

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

**Filing Requirement Page # Reference**

**Date: August 28, 2017**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **16** | Rate Base and DSP - major drivers of DSP, rate base for test year, change in rate base from last approved ($ and %), capital expenditures requested for the test year, change in capital expenditures from last approved ($ and %), summary of costs requested for renewable energy connections/expansions, smart grid, and regional planning initiatives, any O.Reg 339/09 planned recovery | **Yes** | Exhibit A, Tab 3, Schedule 1 and Exhibit C1, Tab 1, Schedule 1 and Exhibit B1, Tab 1, Schedule 1, section 1.3 |
| **16** | OM&A Expense - OM&A for test year and change from last approved ($ and %), summary of drivers, inflation assumed, total compensation for test year and change from last approved ($ and %). | **Yes** | Exhibit A, Tab 3, Schedule 1; OM&A: Exhibit D1, Tab 1, Schedule 1; Inflation assumed: Exhibit A, Tab 1, Schedule 1; Total Compensation: Exhibit D2, Tab 5, Schedule 2 |
| **16** | Cost of Capital - Statement regarding use of OEB's cost of capital parameters; summary of any deviations | **Yes** | Exhibit A, Tab 3, Schedule 1 and Exhibit F1, Tab 1, Schedule 1 |
| **16** | Cost Allocation & Rate Design - summary of any deviations from OEB methodologies, significant changes proposed to revenue-to-cost ratios and fixed/variable splits and summary of proposed mitigation plans | **N/A** | Exhibit A, Tab 3, Schedule 1. The methodology for setting rates for Remotes customers is established under O.Reg 442/01 |
| **17** | Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested | **Yes** | Exhibit A, Tab 3, Schedule 1 and Exhibit H1, Tab 1, Schedule 1 |
| **17** | Bill Impacts - total impacts ($ and %) for all classes for typical customers | **Yes** | Exhibit A, Tab 3, Schedule 1 and Exhibit G2, Tab 3, Schedule 3 |
| *Customer Engagement* | | | |
| **17** | Overview of customer engagement activities; description of plans and how customer needs, preferences and expectations have bee reflected in the application. | **Yes** | Exhibit A, Tab 4, Schedule 1 and Exhibit B1, Tab 1, Schedule 1, section 4.1.5 |
| **17** | Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates | **Yes** | Exhibit A, Tab 4, Schedule 1 |
| **17** | Discussion of any feedback provided by customers and how the feedback shaped the final application | **Yes** | Exhibit A, Tab 4, Schedule 1 |
| **17** | Reference to any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities | **Yes** | Exhibit A, Tab 4, Schedule 1 and Exhibit B1, Tab 1, Schedule 1, section 4.1.5 |
| **17** | Complete Appendix 2-AC Customer Engagement Activities Summary - explicit identification of the outcomes of customer engagement in terms of the impacts on the distributor's plans, and how that information has shaped the application | **Yes** | Exhibit A, Tab 4, Schedule 1, attachment 1 |
| **17** | All responses to matters raised in letters of comment filed with the OEB | **N/A** | No letters of comment were filed with the OEB in regards to this application. |
| *Performance Measurement* | | | |
| **17 & 18** | Discussion of performance for each of the distributor's scorecard measures over the last five years; drivers for its performance, plans for continuous improvement, identify performance improvement targets, forecast of efficiency assessment using the PEG forecasting model for the test year, discussion on how the results obtained from the PEG model has informed the business plan and application | **Yes** | Exhibit A, Tab 5, Schedule 1 |
| *Financial Information* | | | |
| **18** | Non-consolidated Audited Financial Statements for 2 most recentyears (i.e. 3 years of historical actuals) | **Yes** | Exhibit A, Tab 8, Schedule 3, attachments 1 to 4 |
| **18** | Detailed reconciliation of AFS with regulatory financial results filed in the application, with identification of any deviations that are beir proposed | **Yes** | Exhibit A, Tab 8, Schedule 4 |
| **18** | Annual Report and MD&A for most recent year of distributor and parent company, if applicable | **Yes** | Exhibit A, Tab 8, Schedule 6, attachments 1 to 4 |
| **18** | Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances | **Yes** | The rating agency reports are performed at the holding company level. Remotes does not impact these reports. |
| **19** | Any change in tax status | **N/A** | No change in tax status |
| **19** | Existing accounting orders and departures from the accounting orders and USoA | **Yes** | Exhibit A, Tab 8, Schedule 4 |
| **19** | Accounting Standards used for financial statements and when adopted | **Yes** | Exhibit A, Tab 8, Schedule 1 |
| **19** | Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities | **N/A** | Remotes does not have any non-utility business |
| *Distributor Consolidation* | | | |
| **19** | If a distributor has acquired or amalgamated with another distributor, identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement. A distributor must specify whether any commitments made to shareholders are to be funded through rates | **N/A** | Remotes has not nor expects to participate in any acquisition or amalgamation activities within the historic, bridge or test years of this application. |
| **19** | Description of actual savings as a result of consolidation compared to what was in the approved consolidation application and explanation of how savings are sustainable and the efficacy of any rate plan approved as part of the MAADs application | **N/A** | Remotes has not nor expects to participate in any acquisition or amalgamation activities within the historic, bridge or test years of this application. |

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

**Filing Requirement Page # Reference**

**Date: August 28, 2017**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **EXHIBIT 2 - RATE BASE** | | | |
| *Overview* | | | |
| **20** | Completed Fixed Asset Continuity Schedule (Appendix 2-BA) - in Application and Excel format | **Yes** | Exhibit C2, Tab 2, Schedule 1, attachments 1 to 6 |
| **20** | Opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance (historical actuals, bridge and test year forecast) | **Yes** | Exhibit C1, Tab 1, Schedule 1 |
| **20** | Continuity statements (year end balance, including interest during construction and overheads).<br>Explanation for any restatement (e.g. due to change in accounting standards)<br>Year over year variance analysis; explanation where variance greater than materiality threshold<br>Hist. OEB-Approved vs Hist. Actual<br>Hist. Act. vs. preceding Hist. Act.<br>Hist. Act. vs. Bridge<br>Bridge vs. Test | **Yes** | Exhibit C1, Tab 1, Schedule 1 and Exhibit C2, Tab 2 , Schedule 1, Attachments 1 to 5 (App.2-BA) |
| **20 & 21** | Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (e.g.. WIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation | **Yes** | Exhibit C1, Tab 1, Schedule 1 and Exhibit C2, Tab 2 , Schedule 1, Attachments 1 to 5 (App.2-BA) |
| *Gross Assets - PP&E and Accumulated Depreciation* | | | |
| **21** | Breakdown by function and by major plant account; description of major plant items for test year | **Yes** | Exhibit C2, Tab 2 , Schedule 1, Attachment 6 |
| **21** | Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications | **N/A** | Remotes has not requested any ICM or ACM in its IRM applications |
| **21** | Continuity statements must reconcile to calculated depreciation expenses and presented by asset account | **Yes** | Exhibit C2, Tab 2 , Schedule 1, Attachments 1 to 5 (App.2-BA) and Exhibit E1, Tab 6, Schedule 1 |
| **21** | All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years and if any amounts related to gains or losses on disposals have been included in Account 1575 IFRS - CGAAP Transitional PP&E Amount | **Yes** | Exhibit C2, Tab 2 , Schedule 1, Attachments 1 to 5 (App.2-BA) |
| *Allowance for Working Capital* | | | |
| **22** | Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction | **Yes** | Exhibit C1, Tab 1, Schedule 1 |
| **22** | Lead/Lag Study - leads and lags measured in days, dollar-weighted | **N/A** | Remotes is using the default allowance |
| **22** | Cost of Power must be determined by split between RPP and non-RPP customers based on actual data, use most current RPP (TOU) price, use current UTR. Should include SME charge. | **N/A** | Remotes' customers are not part of the Regulated Price Plan. (Rates are bundled and established through RRRP Regulation) |

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## Hydro One Remote Communities Inc.

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|---|---|---|---|
| *Capital Expenditures* | | | |
| 23 | DSP filed as a stand-alone document; a discrete element within Exhibit 2 | Yes | Remotes stand alone DSP has been filed as Exhibit B1, Tab 1, Schedule 1 |
| 23 | Complete Appendix 2-AB - four historical years must be actuals, forecasts for the bridge and test years; at a minimum, for historical years, applicants must provide actual totals for each DSP category. If no previous plan has been filed, applicants are only required to enter their planned total capital budget in the "plan" column for each historical year and for the bridge year including the OEB-approved amount for the last rebasing year | Yes | Exhibit C2, Tab 2, Schedule 3 for years 2013 to 2022 |
| 23 & 24 | Complete Appendix 2-AA along with: explanation for variances, including that of actuals v. OEB-approved amounts for last OEB-approved CoS application; for capital projects that have a project life cycle greater than one year, the proposed accounting treatment including the treatment of the cost of funds for construction work-in-progress | Yes | Exhibit C2, Tab 2, Schedule 2 for years 2013 to 2022 |
| 24 | Statement that there are no non-distribution activities in the applicant's budget | N/A | Both generation and distribution activities are regulated and included as part of this application. See Exhibit A, Tab 2, Schedule 3 |
| 24 | If applicable, details of any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include, initial forecast used to calculate contribution, amount of contribution (if any), true up dates and potential true-up payments | N/A | Remotes is not connected to the transmission system and has not been required to pay capital contributions for transmission build |
| 24 | Discussion outlining capital and operating efficiencies realized as a result of the deployment and operationalization of smart meters and related technologies (e.g., AMI communications networks, ODS) in its networks. Qualitative and quantitative description and support should be provided as applicable | Yes | Exhibit B1 (DSP), Sections 2 and 4 |
| 24 | Description of how incremental conservation initiatives have been considered in order to defer or avoid future infrastructure projects as part of distribution system planning processes | Yes | Exhibit B1 (DSP), Section 1.4.4 |
| 24 & 25 | If applying for funding through distribution rates to pursue activities such as energy efficiency programs, demand response programs energy storage programs etc. the application must include a consideration of the projected affects to the distribution system on a long term basis and the projected expenditures. Distributors should explain the proposed program in the context of the distributors five year Distribution System Plan or explain any changes to its system plans that are pertinent to the program | Yes | Exhibit B1 (DSP), Section 1.4.4 |
| 26 | Changes to capitalization policy since its last rebasing application as a result of the OEB's letter dated July 17, 2012 or for any other reasons, the applicant must identify the changes and the causes of the changes. | N/A | No changes to capitalization policy. |
| 27 | Appendix 2-D complete; identification of burden rates and burden rates prior to changes, if any | Yes | Exhibit C2, Tab 7, Schedule 1 |
| 27 | Generation Facilities - If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09. Request for rate protection exceeds the materiality threshold in section 2.0.8 of the Filing Requirements<br>- Appendices 2-FA through 2-FC identifying all eligible investments for recovery | N/A | Remotes recovers all costs through INAC. See Exhibit A, Tab 3, Schedule 3 for details of the REINDEER program. |
| *New Policy Options for the Funding of Capital* | | | |
| 28 | Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP). Provide cost and materiality calculations to demonstrate ACM qualification | N/A | Remotes is not proposing ACM capital treatment for any capital projects |
| 28 | Distributor must establish need for and prudence of these projects based on DSP information; identification that distributor is proposing ACM treatment for these future projects, preliminary cost information | Yes | See Exhibit B (DSP) Section 4 and DSP Attachment A |
| 28 | Complete Capital Module Applicable to ACM and ICM | N/A | Remotes is not proposing ACM capital treatment for any projects |
| *Addition of ICM Assets to Rate Base* | | | |
| 29 | Distributor with previously approved ICM(s) - schedule of ICM amounts proposed to be incorporated into rate base, variances and explanation | N/A | Remotes has not requested ACM capital treatment in its IRM applications |
| 29 | Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue | N/A | Remotes does not have a balance in Account 1508 sub-accounts. |
| *Service Quality and Reliability Performance* | | | |
| 29 & 30 | 5 historical years of ESQRs, explanation for any under-performance vs standard and actions taken | Yes | Exhibit A, Tab 5, Schedule 2 |
| 30 | 5 historical years of SAIDI and SAIFI - for all interruptions, all interruptions excluding loss of supply, and all interruptions excluding major events. The applicant should also provide a summary of major events that occurred since last rebasing. For each interruption set out in section 2.1.4.2.5 of the RRR, for the last 5 years, a distributor must report on the following data: name of the Cause of Interruption, number of interruptions that occurred as a result of the Cause of Interruption, Number of Customer Interruptions that occurred as a result of the Cause of Interruption, and the Number of customer-hours of Interruptions that occurred as a result of the Cause of Interruption | Yes | Exhibit A, tab 5, Schedule 2 |
| 30 | Explanation for any under-performance vs 5 year average and actions taken | Yes | Exhibit A, Tab 5, Schedule 2 |
| 30 | Distributors may propose SAIDI and SAIFI benchmarks different than 5 year average; provide rationale | N/A | Remotes is not proposing different benchmarks |
| 30 | Completed Appendix 2-G | Yes | Exhibit A, Tab 5, Schedule 2, attachment 1 |

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|---|---|---|---|
| Ch 5 p9 | Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table | Yes | Exhibit B1, Tab 1, Schedule 1, section 1.2 |
| Ch 5 p9-10 | Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies | Yes | Exhibit B1, Tab 1, Schedule 1, section 2.1 |
| Ch 5 p10-11 | Coordinated Planning with 3rd parties - description of consultations<br>- deliverables of the Regional Planning Process, or status of deliverables<br>- OPA letter in relation to REG investments (Ch 5 p8&9) and Dx response letter | Yes | Exhibit B1, Tab 1, Schedule 1, section 2.2 |
| Ch 5 p11 | Performance Measurement - identify and define methods and measures used to monitor DSP performance<br>- summary of performance and trends over historical period. Must include SAIFI and SAIDIfor all interruptions and all interruptions excluding loss of supply<br>- explain how information has affected DSP | Yes | Exhibit B1, Tab 1, Schedule 1, section 2.3 |
| Ch5 p12 | Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments | Yes | Exhibit B1, Tab 1, Schedule 1, section 3.1 |
| Ch5 p12 | Inputs/Outputs of the AM process and information flow for investments; flowchart recommended | Yes | Exhibit B1, Tab 1, Schedule 1, section 3 |
| Ch 5 p13 | Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP),<br>- description of system configuration<br>- service profile and condition by asset type (tables and/or figures) - date data compiled<br>- assessment of degree the capacity of system assets is utilized | Yes | Exhibit B1, Tab 1, Schedule 1, section 3.2 |
| Ch 5 p13-14 | Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions<br>- description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation | Yes | Exhibit B1, Tab 1, Schedule 1, section 3.3 |
| Ch 5 p14-15 | Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category<br>- list, description and total capital cost of material capital expenditures sorted by category (table recommended)<br>- information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate)<br>- description of customer engagement<br>- Dx expectations of system development over next 5 years<br>- list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended) | Yes | Exhibit B1, Tab 1, Schedule 1, section 4.1 |
| Ch 5 p15 | Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritise REG investments | Yes | Exhibit B1, Tab 1, Schedule 1, section 4.2 |
| Ch 5 p16 | System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints | Yes | Exhibit B1, Tab 1, Schedule 1, section 4.3 |
| Ch 5 p16-18<br>Ch 2 p24 | Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year<br>Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB (must provide actual totals for historical years, as a minimum) | Yes | Exhibit B1, Tab 1, Schedule 1, section 4.4.<br>OEB Chapter 2, Appendix 2-AB for the years 2013 to 2022 is found in Exhibit C2, Tab 2, Schedule 3. |
| Ch5 p19 | Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment | Yes | Exhibit B1, Tab 1, Schedule 1, sections 4.5 and 4.5.1 |
| Ch 5 p19-25 | Material Investments - For each project that meets materiality threshold set in Ch 2 p10<br>- general information - total capital, customer attachments, dates, risks, variances, REG investments<br>- evaluation criteria - may include: efficiency, customer value, reliability, etc.<br>- category specific requirements for each project - system access, system renewal, system service, general plant (as applicable) | Yes | Exhibit B1, Tab 1, Schedule 1, section 4.5.2 and appendix A. |

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|---|---|---|---|
| **EXHIBIT 3 - OPERATING REVENUE** | | | |
| *Load and Revenue Forecasts* | | | |
| 31 | Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts | Yes | Exhibit G1, Tab 1, Schedule 1 |
| 31 | Explanation of weather normalization methodology | N/A | Remotes does not normalize its load forecast for weather. |
| 31 | Quantification of any impacts arising from the persistence of historical CDM programs as well as the forecasted impacts arising from new programs in the bridge and test years through the current 6-year CDM framework by customer class | Yes | Exhibit B1, Tab 1, Schedule 1, section 1.4.4 |
| 31 | Completed Appendix 2-IB; the customer and load forecast for the test year must be entered on RRWF, Tab 10 | Yes | Exhibit , Tab 1, Schedule 1 |
| 31 & 32 | Multivariate Regression Model - rationale for choice, regression statistics, explanation of weather normalization methodology, source of data for endogenous and exogenous variables, any binary variables used to either account for individual data points or to account for seasonal or cyclical trends or for discontinuities in the historical data, explanation of any specific adjustments made; data used in load forecast must be provided in Excel format, including derivation of constructed variables | N/A | Remotes does not use a multivariate regression model for load forecast. |
| 32 & 33 | NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including licence conditions, discussion of weather normalization considerations | Yes | Exhibit G1, Tab 1, Schedule 1 |
| 33 | CDM Adjustment - account for CDM in 2018 load forecast. Consider impact of persistence of historical CDM and impact of new programs. Adjustments may be required for IESO reported results which are full year impacts | N/A | Remotes does not adjust the load forecast to account for CDM and will not be applying for an LRAM. |
| 33 | CDM savings for 2018 LRAMVA balance and adjustment to 2018 load forecast; data by customer class and for both kWh and, as applicable, kW. Provide rationale for level of CDM reductions in 2018 load forecast | N/A | Remotes does not adjust the load forecast to account for CDM and will not be applying for an LRAM. |
| 33 | Completed Appendix 2-I | N/A | Remotes does not adjust the load forecast to account for CDM and will not be applying for an LRAM. |
| *Accuracy of Load Forecast and Variance Analyses* | | | |
| 33 | Completed Appendix 2-IB | Yes | Exhibit G2, Tab 1, Schedule 1 |
| 34 | For customer/connection counts - identification as to whether customer/connection count is shown in year end or average format, year-over-year variances in changes of customer/connection counts with explanation of major changes, explanations of bridge and test year forecasts by rate class, for last rebasing variance analysis between last OEB-approved and actuals with explanations for material differences | Yes | Exhibit G2 Tab 1 Schedule 2 |
| 34 | For consumption and demand - explanation to support how kWh are converted to kW for applicable demand-billed classes, year-over-year variances in kWh and kW by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (should be done for both historical actuals against each other and historical weather-normalized actuals over time), explanations of the bridge and test year forecasts by rate class, variance analysis between the last OEB-approved and the actual and weather-normalized actual results | N/A | Remotes does not have customers who are demand billed. |
| 34 | For revenues - calculation of bridge year forecast of revenues at existing rates, calculation of test year forecasted revenues at existing and proposed rates, year-over-year variances in revenues comparing historical actuals and bridge and test year forecasts | Yes | Exhibit G2, Tab 2, Schedule 2 and Exhibit G2, Tab 1, Schedule 1 |
| 35 | With respect to average consumption, for each rate class, distributors are to provide weather-actual and weather-normalized average annual consumption or demand per customer as applicable for the rate class for last OEB approved and historical, weather normalized average annual consumption or demand per customer for the bridge and test years, explanation of the net change in average consumption from last OEB-approved and actuals from historical, bridge and test years based on year-over-year variances and any apparent trends in data | N/A | Weather data is not available for Remotes service territory |
| *Other Revenue* | | | |
| 35 | Completed Appendix 2-H | Yes | Exhibit G2, Tab 2, Schedule 1 |
| 35 | Variance analysis - year over year, historical, bridge and test | Yes | Exhibit G2, Tab 1, Schedule 3 |
| 35 | Any new proposed specific service charges, or proposed changes to rates or application of existing specific service charges | N/A | Remotes is not proposing any new specific charges. |
| 35 | Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs (Appendix 2-N) | Yes | Exhibit D2, Tab 4, Schedule 1 |
| 35 | Distributors must identify any discrete customer groups that may be materially impacted by changes to other rates and charges | N/A | An increase of 1.8% is proposed for all customer classes at all levels of consumption |

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|---|---|---|---|
| **EXHIBIT 4 - OPERATING COSTS** | | | |
| *Overview* | | | |
| **36** | Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes | **Yes** | OM&A: Exhibit D1, Tab 1, Schedule 1 to 5; Inflation assumed: Exhibit A, Tab 1, Schedule 1 |
| *Summary and Cost Driver Tables* | | | |
| **36** | Summary of recoverable OM&A expenses; Appendix 2-JA | **Yes** | Exhibit D2 , Tab 3, Schedule 1 |
| **36** | Recoverable OM&A cost drivers; Appendix 2-JB | **Yes** | Exhibit D2, Tab 3, Schedule 2 |
| **36** | Recoverable OM&A Cost per customer and per FTE; Appendix 2-L | **Yes** | Exhibit D2, Tab 3, Schedule 4 |
| **37** | Identification of change in OM&A in test year in relation to change in capitalized overhead. | **Yes** | Exhibit C2, Tab 7, Schedule 1 |
| **36** | OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-D | **Yes** | Exhibit C2, Tab 7, Schedule 1 |
| *Program Delivery Costs with Variance Analysis* | | | |
| **37** | Completed Appendix 2-JC OM&A Programs Table - completed by program or major functions; include variance analysis limited to variances that are outliers, between test year and last OEB approved and most recent actuals, including an explanation for each significant change whether the change was within or outside the applicant's control and explanation of why | **Yes** | Exhibit D2, Tab 3, Schedule 3 |
| **37** | For each significant change within the applicant's control describe business decision that was made to manage the cost increase/decrease and the alternatives | **Yes** | Exhibit B1, Tab 1, Schedule 1, section 4.1 for Capital and Exhibit D1, Tab 1, Schedules 2 to 5 for OM&A |
| *Workforce Planning and Employee Compensation* | | | |
| **37** | Employee Compensation - completed Appendix 2-K | **Yes** | Exhibit D2, Tab 5, Schedule 2 |
| **38** | Description of previous and proposed workforce plans, including compensation strategy | **Yes** | Exhibit D1, Tab 3, Schedule 1 |
| **38** | Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to headcount and compensation. Explanation for all years includes:<br>- year over year variances<br>- basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans,<br>- relevant studies (e.g. compensation benchmarking) | **Yes** | Exhibit D1, Tab 3, Schedule 1 and Exhibit D2, Tab 5, Schedule 1 |
| **38** | Details of employee benefit programs including pensions for last OEB approved, historical, bridge and test; must agree with tax section | **Yes** | Exhibit D2, Tab 5, Schedules 2 to 3 |
| **38** | Most recent actuarial report on employee benefits, pension and OPEBs | **N/A** | The actuarial report is performed at the holding company level. Remotes does not impact the report. An actuarial account is not performed on Remotes. |
| **38** | Accounting method for pension and OPEBs; if cash method, sufficient supporting rationale. If proposing to change the basis in which pension and OPEB costs included in OM&A, quantification of impact of transition | **Yes** | Exhibit E1, Tab 3, Schedule 2 |
| *Shared Services and Corporate Cost Allocation* | | | |
| **39** | Identification of all shared services among affiliates and parent company; identification of the extent to which the applicant is a "virtual utility" | **Yes** | All shared services between the affiliate and parent company are covered by Affiliate Services Agreement Exhibit A, Tab 6, Schedule 1. Details are found in Exhibit D2, Tab 4, Schedule 1 |
| **39** | Allocation methodology for corporate and shared services, list of costs and allocators, including any third party review | **Yes** | Exhibit D2, Tab 4, Schedule 1 |
| **39** | Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue | **Yes** | Exhibit D2, Tab 4, Schedule 1 |
| **39** | Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and most recent actual | **Yes** | Exhibit E1, Tab 1, Schedule 1 |
| **39** | Identification of any Board of Director costs for affiliates included in LDC costs | **Yes** | Remotes pays for services from HOI that include Board of Director services. See Exhibit E2-04-01 |
| *Non-Affiliate Services, One-Time Costs, Regulatory Costs* | | | |
| **39** | Purchased Non-Affiliated Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance) | **Yes** | Exhibit A, Tab 6, Schedule 2 and Exhibit A, Tab 6, Schedule 2, attachment 1 |
| **39** | For material transactions that are not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor | **Yes** | Exhibit A, Tab 6, Schedule 2 |
| **40** | Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years). If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided | **Yes** | Exhibit D1, Tab 1, Schedule 6 |
| **40** | Regulatory costs - breakdown of actual and forecast, supporting information related to CoS application (e.g. legal fees, consultant fees), proposed recovery (i.e. amortized?) Completed Appendix 2-M | **Yes** | Exhibit D2, Tab 6, Schedule 1 |
| *LEAP, Charitable and Political Donations* | | | |
| **40** | LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes | **Yes** | Exhibit D1, Tab 1, Schedule 6 |
| **41** | Detailed information for all contributions that are claimed for recovery | **Yes** | Exhibit D1, Tab 4, Schedule 1 |

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|---|---|---|---|
| 41 | Charitable Donations - the applicant must confirm that no political contributions have been included for recovery | N/A | Remotes has not requested the recovery of any political donations. |
| *Depreciation, Amortization and Depletion* | | | |
| 41 | Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report | N/A | Remotes is not proposing any changes in depreciation related to useful life of assets |
| 41 | Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate o depreciation/amortization. Must agree to accumulated depreciation in Appendix 2-BA under rate base | Yes | Exhibit D2, Tab 7, Schedule 1 and Exhibit C2, Tab 1, Schedule 1, attachments 1 to 6, and Exhibit D2, Tab 20, Schedule 1, attachments 1 to 6 |
| 41 | Identification of any Asset Retirement Obligations and associated depreciation, accretion expense | Yes | Remotes has a Land Assessment Remediation (LAR) program. Refer to Exhibit D1, Tab 6, Schedule 1 |
| 41 & 42 | Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided | Yes | Exhibit E1, Tab 6, Schedule 1. There are no variances from half year rule. |
| 42 | Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS | N/A | Depreciation policy has not changed since 2012 |
| 42 | Explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately | N/A | There were no deviations |
| 42 | For any depreciation expense policy or asset service lives changes since its last rebasing application:<br>- identification of the changes and detailed explanation for the causes of the changes, including any changes subsequent to those made by January 1, 2013<br>-use of Kinectrics study or another study to justify changes in useful life<br>- list detailing all asset service lives tied to USoA, detail differences in TUL from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB<br>-File applicable depreciation appendices as provided in Chapter 2 MIFRS Appendices (Appendix 2-CA to 2-CK) | N/A | No change from previous rebasing |
| *PILs and Property Taxes* | | | |
| 43 | Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test years | Yes | Remotes prepared its own PILs worksheet at Exhibit D2, Tab 8, Schedules 2 and 3 |
| 43 | Supporting schedules and calculations identifying reconciling items | Yes | Exhibit D2, Tab 8, Schedules 1 and 3 |
| 43 | Most recent federal and provincial tax returns | Yes | Exhibit D2, Tab 9, Schedule 1, attachments 1 to 6 |
| 18 & 43 | Financial Statements included with tax returns if different from those filed with application | N/A | Remotes financial statements were not different |
| 43 | Calculation of Tax Credits; redact where required (filing of unredacted versions is not required) | N/A | No tax credits were estimated in the Remotes Business Plan |
| 43 | Supporting schedules, calculations and explanations for other additions and deductions | Yes | Exhibit D2, Tab 8, Schedules 2 and 4 |
| 43 | Completion of the integrity checks in the PILs Model | N/A | Remotes prepared its own PILs worksheet |
| 41 | Explanation of how taxes other than income taxes or PILS (e.g. property taxes) are derived | Yes | Exhibit D1, Tab 7, Schedule 2 |
| *Non-recoverable and Disallowed Expenses* | | | |
| 43 | Exclude from regulatory tax calculation any non-recoverable or disallowed expenses | N/A | No non-recoverable or disallowed expenses were included in the Remotes' tax calculations. |
| *Conservation and Demand Management* | | | |
| 44 & 45 & 46 | LRAMVA - disposition of balance. Distributors must provide new LRAMVA Work form in a working Excel file and provide the following:<br>- statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition<br>- statement confirming LRAMVA based on verified savings results supported by the distributors final CDM Report and Persistence Savings Report (both filed in Excel format) and a statement indicating use of most recent input assumptions when calculating lost revenue<br>- summary table with principal and carrying charges by rate class and resulting rate riders<br>- statement providing the disposition period; rationale provided for disposing the balance in the LRAMVA if one or more classes do not generate significant rate riders<br>- statement confirming LRAMVA reference amounts, rationale for the distributors circumstances if LRAMVA threshold not used<br>- rationale confirming how rate class allocations for actual CDM savings were determined by class and program (Tab 3-A of LRAMVA Work form)<br>- statement confirming whether additional documentation was provided in support of projects that were not included in distributors final CDM Annual Report (Tab 8 of LRAMVA Work form as applicable)<br>- for OEB-approved programs prior to 2014, a submission of a third party report that provides a review and verification of the LRAM calculation including: confirmation of use of correct input assumptions and lost revenue calculations, participation amounts, net and gross impacts of each program (kW and kWh) by class by year, and verification of any carrying charges requested | N/A | Remotes does not have an LRAMVA |

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| | | | Date: August 28, 2017 |
| **EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE** | | | |
| *Capital Structure* | | | |
| 46 | Statement that LDC adopts OEB's guidelines for cost of capital and confirms that updates will be done. Alternatively - utility specific cost of capital with supporting evidence | Yes | Exhibit E1, Tab 1, Schedule 1 |
| 46 | Completed Appendix 2-OA for last OEB approved and test year | Yes | Exhibit E2, Tab 1, Schedule 1 (2013) and Exhibit E2, Tab 1, Schedule 2 (2018) |
| 46 | Completed Appendix 2-OB for historical, bridge and test years | Yes | Exhibit E2, Tab 2, Schedule 1, attachments 1 to 6 |
| 46 | Explanation for any changes in capital structure | Yes | Exhibit E1, Tab 1, Schedule 1 |
| *Cost of Capital (Return on Equity and Cost of Debt)* | | | |
| 47 | Calculation of cost for each capital component | Yes | Exhibit E2, Tab 1, Schedule 1 (2013) and Exhibit E2, Tab 1, Schedule 2 (2018) |
| 47 | Profit or loss on redemption of debt | N/A | Remotes did not have any redemption of debt |
| 47 | Copies of promissory notes or other debt arrangements with affiliates | N/A | Remotes has no affiliates |
| 47 | Explanation of debt rate for each existing debt instrument | Yes | Exhibit E1, Tab 1, Schedule 1 |
| 47 | Forecast of new debt in bridge and test year - details including estimate of rate | N/A | Remotes is not forecasting new debt in bridge and test years |
| 47 | If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions | N/A | Remotes' rate based on the OEB's Cost of Capital Parameter Updates for 2017 COS Applications for Rates Effective January 1, 2017, dated October 27, 2016. |
| 47 | Notional Debt - difference between actual debt thickness and deemed debt thickness attracts the weighted average cost of actual long-term debt rate (unless 100% equity financed) | Yes | Exhibit E1, Tab 1, Schedule 1. Remotes is 100% debt-financed and is operated as a break-even company. |
| *Not-for-Profit Corporations* | | | |
| 48 | Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves | N/A | Remotes is not a Not-for-Profit Corporation. Remotes is set up under the Business Corporations Act. Exhibit A, Tab 2, Schedule 1 |
| 48 | Detailed calculation for test year revenue requirement based on its Reserve Requirement | N/A | Remotes is not a Not-for-Profit Corporation. Remotes is set up under the Business Corporations Act. Exhibit A, Tab 2, Schedule 1 |
| 48 | The proposed reserves and rationale for the need to establish each reserve, the time period of building up the reserves, and the procedure and policy of each reserve | N/A | Remotes is not a Not-for-Profit Corporation. Remotes is set up under the Business Corporations Act. Exhibit A, Tab 2, Schedule 1 |
| 48 | Description of the governance of the not-for-profit corporation | N/A | Remotes is not a Not-for-Profit Corporation. Remotes is set up under the Business Corporations Act. Exhibit A, Tab 2, Schedule 1 |
| 48 & 49 | If there are approved reserves from previous OEB decisions provide the following:<br>-any changes to the reserve policies and rationale for the changes since last CoS<br>limits of any capital and/or operating reserves as approved by the OEB and identify decisions<br>-current balances of any established capital and/or operating reserves<br>-list withdrawals from capital and operating reserves, identify amounts and purpose of withdrawal<br>-if limits on capital and operating reserves achieved provide a proposal for utilization of amounts<br>-if limits on reserves not achieved provide rationale and the detail for its forecast of the Reserve Requirement for the test year | N/A | Remotes is not a Not-for-Profit Corporation. Remotes is set up under the Business Corporations Act. Exhibit A, Tab 2, Schedule 1 |
| **EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY** | | | |
| 49 | Calculation of delivery-related Revenue Deficiency/Sufficiency (excluding cost of power and associated costs): net utility income, rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency/sufficiency, gross deficiency/sufficiency. Deficiency/sufficiency must also be net of other costs (e.g. LV costs, RSVAs, smart meter or MIST meter expenditures/revenues and other DVA balances). | Yes | Exhibit F1, Tab 1, Schedule 1 |
| 49 & 50 | Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers | Yes | Exhibit F2, Tab 1, Schedules 1 and 2 |
| 50 | Impacts of any changes in methodologies to deficiency/sufficiency | N/A | There has been no change in methodology. |
| *Revenue Requirement Work Form* | | | |
| 50 | RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits | Yes | Exhibit F2, Tab 1, Schedule 2 |
| 50 | If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model | Yes | Exhibit G3, Tab 3, Schedule 4 |

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

**Date: August 28, 2017**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **EXHIBIT 7 - COST ALLOCATION** | | | |
| *Cost Allocation Study Requirements* | | | |
| 51 | Completed cost allocation study using the OEB-approved methodology or a comparable model must be filed reflecting future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. Sheets 11 and 12 of the RRWF must also be completed. Live Excel version of 2017 cost allocation model will be filed (updated load profiles or scaled version of HONI CAIF). Model must be consistent with test year load forecast, changes to customer classes and load profiles. | N/A | The methodology for setting rates for Remotes customers is established under O.Reg 442/01 |
| 51 | Explanation provided if a distributor is unable to update its load profiles and confirm that it intends to put plans in place to update its load profiles the next time a cost allocation model is filed | N/A | The methodology for setting rates for Remotes customers is established under O.Reg 442/01 |
| 52 | Description of weighting factors, and rationale for use of default values (if applicable) | N/A | The methodology for setting rates for Remotes customers is established under O.Reg 442/01 |
| 52 | Hard copy of sheets I-6, I-8, O-1 and O-2 (first page) | N/A | The methodology for setting rates for Remotes customers is established under O.Reg 442/01 |
| 52 & 53 | Host Distributor only<br>- evidence of consultation with embedded Dx<br>- statement regarding embedded Dx support for approach to allocation of costs<br>- if embedded Dx is separate class - class in cost allocation study and RRWF, Sheet 11<br>- if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and RRWF, Sheet 11<br>- if embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. File Appendix 2-Q. | N/A | Remotes does not have any embedded distributors |
| 53 | Unmetered Loads (including Street Lighting) - Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges | N/A | Remotes has seven street lighting accounts that are unmetered. No changes are requested to unmetered load accounts. Rates are increasing for all customers by 1.8%, less than inflation |
| 53 | micro FIT - if the applicant believes that it has unique circumstances which would justify a certain rate, appropriate documentation must be provided | N/A | Remotes does not have any micro FIT customers and is not proposing changes |
| 53 | Standby Rates - if seeking approval on final basis, provide evidence that affected customers have been advised. If seeking changes to standby charges, provide rationale and evidence that affected customer have been advised. | N/A | Remotes does not charge standby rates |
| 54 | New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS | N/A | No new rate classes are proposed |
| *Class Revenue Requirements* | | | |
| 54 | To support a proposal to rebalance rates, the distributor must provide information on the revenue by class that would apply if all rates were changed by a uniform percentage. Ratios must be compared with the ratios that will result from the rates being proposed by the distributor. | N/A | All rates are proposed to increase by 1.8% |
| *Revenue to Cost Ratios* | | | |
| 55 | If R:C ratios outside deadband based on model - distributors must include cost allocation proposal to bring them within the OEB-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rates of any particular class or classes is significant. | N/A | The methodology for setting rates for Remotes customers is established under O.Reg 442/01 |
| 55 | If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters | N/A | The methodology for setting rates for Remotes customers is established under O.Reg 442/01 |

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

**Filing Requirement Page # Reference** | **Date: August 28, 2017**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **EXHIBIT 8 - RATE DESIGN** | | | |
| **56** | Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places | **Yes** | Exhibit G1, Tab 1, Schedule 1 |
| *Fixed Variable Proportion* | | | |
| **56** | The following is to be provided in relation to the fixed/variable proportion of proposed rates:<br>-Current F/V with supporting info<br>-Proposed F/V proportion with explanation for any changes (billing determinants from proposed load forecast)<br>-Comparison between current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study<br>Analysis must be net of rate adders, funding adders, and rate riders | **N/A** | The methodology for setting rates for Remotes customers is established under O.Reg 442/01. Because Remotes' rates include both generation and distribution, Remotes is not planning to move to a fixed monthly charge. See Exhibit G1-02-01 |
| *Rate Design Policy* | | | |
| **57** | LDCs must propose changes to residential rates consistent with policy to transition to fully fixed monthly distribution service charge. | **N/A** | The methodology for setting rates for Remotes customers is established under O.Reg 442/01. Because Remotes' rates include both generation and distribution, Remotes is not planning to move to a fixed monthly charge. See Exhibit G1-02-01 |
| **57** | Proposal follows approach set out in Tab 12 of RRWF | **N/A** | The methodology for setting rates for Remotes customers is established under O.Reg 442/01. |
| **57** | If applicable, distributor with seasonal residential class must propose identical rate design treatment for such a class | **N/A** | The methodology for setting rates for Remotes customers is established under O.Reg 442/01. |
| *RTSRs* | | | |
| **58** | Retail Transmission Service Rate Work Form - PDF and Excel | **N/A** | Remotes is not connected to the transmission grid |
| **58** | RTSR information must be consistent with working capital allowance calculation | **N/A** | Remotes is not connected to the transmission grid |
| *Retail Service Charges* | | | |
| **58** | If proposing changes to Retail Service Charges or introduction of new rates and charges - evidence of consultation and notice | **N/A** | Remotes is not proposing changes nor introducing any new rates or charges. |
| *Regulatory Charges* | | | |
| **58 & 59** | Wholesale Market Service Rate - reflect current approved rate in application or justify otherwise | **N/A** | This does not apply to Remotes. |
| *Specific Service Charges* | | | |
| **59** | Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges | **N/A** | Remotes is not proposing new or revised SSC |
| **59** | Identification in the Application Summary all proposed changes that will have a material impact on customers, including charges that may affect a discrete group. | **Yes** | Exhibit G1, Tab 2, Schedule 1 and supporting schedules |
| **59** | Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions 2012-2015, bridge and test years.<br>Whether these charges should be included on tariff sheet | **N/A** | All rates and charges appear on the Tariff Sheet. |
| **59** | Ensure revenue from SSCs corresponds with Operating Revenue evidence | **Yes** | Exhibit G1, Tab 3, Schedule 1 and Exhibit G1, Tab 4, Schedule 1 |
| *Low Voltage Service Rates* | | | |
| **60** | Forecast of LV cost, sum of host distributors charges | **N/A** | Remotes is not a host nor an embedded distributor. |
| **60** | Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes | **N/A** | Remotes is not a host nor an embedded distributor. |
| **60** | Support for forecast LV, e.g. Hydro One Sub-Transmission charges | **N/A** | Remotes is not a host nor an embedded distributor. |
| **60** | Allocation of LV cost to customer classes (typically proportional to Tx connection revenue) | **N/A** | Remotes is not a host nor an embedded distributor. |
| **60** | Proposed LV rates by customer class | **N/A** | Remotes is not a host nor an embedded distributor. |

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

**Date: August 28, 2017**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| *Loss Factors* | | | |
| 60 | Proposed SFLF and Total Loss Factor for test year | N/A | Remotes is an integrated generation and distribution utility |
| 60 | Statement as to whether LDC is embedded including whether fully or partially | Yes | Exhibit A, Tab 2, Schedule 1, Legal Form of Application |
| 60 | Study of losses if required by previous decision | N/A | Remotes has not been directed to complete a study of losses in a previous decision. |
| 60 | 3-5 years of historical loss factor data - Completed Appendix 2-R | N/A | Remotes has no approved loss factors. |
| 60 | If proposed loss factor >5%, explanation and action plan to reduce losses going forward | N/A | Remotes has no approved loss factors. |
| 60 | Explanation of SFLF if not standard | N/A | Remotes has no approved loss factors. |
| *Tariff of Rates and Charges* | | | |
| 60 & 61 | Current and proposed Tariff of Rates and Charges filed in the Tariff Schedule/Bill Impacts Model - each change must be explained and supported in the appropriate section of the application | Yes | Exhibit G1, Tab 2, Schedule 1 and Exhibit G2, Tab 3, Schedules 1 to 2 |
| 61 | Explanation of changes to terms and conditions of service if changes affect application of rates | N/A | Remotes has not proposed any changes. |
| *Revenue Reconciliation* | | | |
| 61 | Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.) | Yes | Exhibit G2, tab 1, Schedule 1 |
| 61 | Completed RRWF - Sheet 13 - rates and charges entered on this sheet should be rounded to the same decimal places as tariff | N/A | Remotes has provided its own version of the RRWF at Exhibit F2, Tab 1, Schedule 2 |
| *Bill Impact Information* | | | |
| 61 | Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill) | N/A | Remotes' rates are set by Regulation. A rate model is provided at Exhibit G, Tab 3, Schedule 4. |
| 61 | Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant | Yes | Exhibit G1, Tab 2, Schedule 1 |
| 61 & 62 | Rates and charges input in the tariff schedule and Bill Impacts Model rounded to the decimal places as shown on the existing tariff | Yes | Exhibit G1, Tab 2, Schedule 1 and Exhibit G, Tab 3, Schedule 4 |
| 62 | Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh, residential at the lowest 10th percentile and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory. | Yes | Exhibit G1, Tab 2, Schedule 1 |
| 62 | If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation | N/A | Remotes is proposing a 1.8% increase for all customers. See Exhibit G1, Tab 2, Schedule 1 |
| *Rate Mitigation* | | | |
| 62 | Evidence showing that the monthly service charge would not rise by more than $4 per year due only to the rate design change, and that the total bill impact, reflecting all proposed changes in the application, will not exceed 10%. If either of these criteria is not met, some form of mitigation may be required (i.e. extending transition period). | Yes | Exhibit G1, Tab 5, Schedule 1 |
| 63 | Evaluation of bill impact for residential customer at 10th consumption percentile. Describe methodology for determination of 10th consumption percentile. File mitigation plan for whole residential class if impact >10% for these customers. | N/A | All proposed increases are les than 10% for all classes at all levels of consumption |
| 63 | Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed. | N/A | All proposed increases are les than 10% for all classes. |
| 64 | Rate Harmonization Plans, if applicable - including impact analysis | N/A | Remotes is not proposing any rate harmonization. |

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

**Filing Requirement Page # Reference**

**Date: August 28, 2017**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS** | | | |
| **64** | List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH | **Yes** | Exhibit H1, Tab 1, Schedule 1 |
| **64** | Completed DVA continuity schedule for period following last disposition to present - live Excel format | **Yes** | Exhibit H2, Tab 1, Schedule 1, attachments 1 to 4 |
| **64** | Confirm use of interest rates established by the OEB by month or by quarter for each year | **N/A** | Remotes does not apply interest |
| **64** | Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS | **N/A** | Account balances reflect the trial balance |
| **64** | Identification of Group 2 accounts that will continue/discontinue going forward, with explanation | **N/A** | Remotes does not have Group 2 accounts |
| **64** | Statement as to any new accounts, and justification. | **N/A** | Remotes is not requesting new accounts |
| **65** | Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents | **N/A** | There were no adjustments made to account balances previously approved by the Board |
| **65** | Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped and reconciled to USoA. Provide explanation if making a profit or loss on commodity. | **N/A** | Exhibit A, Tab 8, Schedule 5. Remotes operates as a break even business. |
| **65** | Statement confirming that IESO GA charge is pro-rated into RPP and non-RPP; provide explanation if not pro-rated. | **N/A** | Remotes does not pay Global Adjustment as Remotes is not connected to the grid. |
| *One-Time Incremental IFRS Costs* | | | |
| **65 & 66** | Request for disposition of Account 1508 sub-account IFRS Transition Costs if balances are still in account and not previously requested for disposition:<br>- completed Appendix 2-YA<br>-statement whether any one time IFRS transition costs are embedded in 2018 revenue requirement, where and why it is embedded, and the quantum<br>- if Account 1508 sub-accounts have been approved for disposition in a prior year, a statement indicating whether prior disposition included forecasted costs<br>-explanation for material variances in Account 1508 sub-account IFRS Transition Costs Variance<br>- explanation on why costs incurred after adoption of IFRS, if any, and the nature of the costs<br>- statement that no capital costs, ongoing IFRS compliance costs are recorded in 1508 sub-account; provide explanation if this is not the case | **N/A** | Consistent with the Board's Decision in EB-2011-0427, Remotes uses US GAAP as its accounting standard |
| *Account 1575, IFRS-CGAAP Transitional PP&E Amounts* | | | |
| **66 & 67** | 1575 IFRS-CGAAP PP&E account<br>- Account 1575 and 1576 can't be used interchangeably<br>- breakdown of balance, including explanation for each accounting change; Appendix 2-EA<br>- listing and quantification of drivers<br>- volumetric rate rider to clear 1575; separate rider must be on a fixed basis for the residential class;<br>- rate of return component is to be applied to 1575 but not recorded in 1575<br>- statement confirming no carrying charges applied to 1575<br>- explanation for the basis of the proposed disposition period to clear Account 1575 rate rider<br>- show the balance in DVA continuity schedule | **N/A** | Consistent with the Board's Decision in EB-2011-0427, Remotes uses US GAAP as its accounting standard |
| *Account 1576, Accounting Changes under CGAAP* | | | |
| **67 & 68** | Changes to depreciation and capitalization in 2012 or 2013 - Account 1576 IFRS-CGAAP PP&E<br>- Appendix 2-BA must not be adjusted for 1576<br>- breakdown of balance related to 1576, Appendix 2-EB or 2-EC<br>drivers of change in closing net PP&E identified and quantified<br>- volumetric rate rider to clear 1576; the rider for the residential class must be on a fixed basis<br>- rate of return component is to be applied to 1576 but not recorded in 1576<br>- statement confirming no carrying charges applied to 1576<br>- explanation for the basis of the proposed disposition period to clear Account 1576 rate rider<br>- show the balance in DVA continuity schedule | **N/A** | Consistent with the Board's Decision in EB-2011-0427, Remotes uses US GAAP as its accounting standard |
| *Retail Service Charges* | | | |
| **68** | Retail Service Charges - material balance in 1518 or 1548 -<br>- confirm variances are incremental costs of providing retail services; identify drivers for balances<br>- provide schedule identifying all revenues and expenses listed by USoA for 2013, actual/forecast for bridge and test year<br>- state whether Article 490 of APH has been followed; explanation if not followed | **N/A** | Remotes does not have activity in 1518 or 1548 as Remotes is exempt from the Retail Service Code. |
| **69** | Retail Service Charges - zero balance in 1518 or 1548 - state whether Article 490 of APH has been followed; explanation if not followed | **N/A** | Remotes is exempt from the Retail Service Code. |

# 2018 Cost of Service Checklist

## Hydro One Remote Communities Inc.

## EB-2017-0051

**Filing Requirement Page # Reference**

**Date: August 28, 2017**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| *Disposition of Deferral and Variance Accounts* | | | |
| 69 | Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why | Yes | Exhibit H1, Tab 1, Schedule 1 |
| 69 | Statement whether DVA balances before forecasted interest match the last AFS; explain any variances | Yes | Exhibit H2, Tab 1, Schedule 1 |
| 69 | Provide an explanation of variance > 5% between amounts proposed for disposition and amounts reported in RRR for each account. | Yes | Exhibit H2, Tab 1 and supporting schedules |
| 69 | Provide explanations if variances are < 5% threshold if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts total to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings | Yes | Exhibit H2, Tab 1 and supporting schedules |
| 69 | For any utility specific accounts requested for disposition, supporting evidence showing how balance is derived and relevant accounting order | Yes | Exhibit H2, Tab 1 and supporting schedules |
| 69 | Disposition of residual balances for vintage Account 1595 are only done once - distributors expected to seek disposition of the balance a year after a rate rider's sunset date has expired. No further dispositions of these accounts are generally expected unless justified by the distributor | N/A | Remotes has no activity in 1595 |
| 69 & 70 | Proposed mechanisms for disposition with all relevant calculations: allocation of each account (including rationale), billing determinants for recovery purposes in accordance with Rate Design Policy | Yes | Exhibit H2, Tab 1 and supporting schedules |
| 70 | Rate riders where volumetric rider is $0.0000 for one or more classes not included in the tariff for those classes | N/A | Remotes rates currently have no riders |
| 70 | Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation. | N/A | Exhibit H1, Tab 1, Schedule 1 |
| 70 | Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the MP's settle directly with the IESO. | N/A | Remotes is not connected to the grid. |
| 70 | Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance.<br>- embedded distributors who are not charged CBR (therefore no balance in sub-account CBR Class B) must indicate this is the case for them<br>- In the DVA continuity schedule, applicants must indicate whether they serve any Class A customers during the period where Account 1580 CBR Class B sub-account balance accumulated.<br>- Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance.<br>- The DVA continuity schedule will allocation the portion of Account 1580 sub-account CBR Class B allocated to customers who transitioned between Class A and Class B based on consumption levels | N/A | Remotes is not connected to the grid. |
| *Global Adjustment* | | | |
| 71 | Establishment of a separate rate rider included in the delivery component of the bill that would apply prospectively to Non-RPP Class B customers when clearing balances from the GA Variance Account | N/A | Remotes customers do not pay Global Adjustment |
| 71 | RPP Settlement True-Up - distributors to follow guidance in May 23, 2017 letter pertaining to the period that is being requested for disposition for Accounts 1588 and 1589 | N/A | Remotes customers do not pay Global Adjustment |
| 71 | GA Analysis Work form in live Excel format- complete GA Analysis Work form; explain discrepancies | N/A | Remotes customers do not pay Global Adjustment |
| 72 | Description of settlement process with IESO or host distributor, specify GA rate used for each rate class, itemize process for providing estimates and describe true-up process, details of method for estimating RPP and non-RPP consumption, treatment of embedded generation/distribution.<br><br>If distributor uses the actual GA rate to bill non-RPP Class B customers, a proposal must be made to exclude these customer classes from the allocations of the balance of Account 1589 and the calculation of the resulting rate riders | N/A | Remotes customers do not pay Global Adjustment |
| 72 | Certification by the CEO, CFO or equivalent that distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition | Yes | Exhibit H1, Tab 1, Schedule 1, Attachment 1 |
| *Establishment of New Deferral and Variance Accounts* | | | |
| 72 & 73 | New DVA - information provided which addresses that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order. | N/A | Remotes is not requesting a new DVA |
| | **TOTAL "NO"** | **0** | |

# TABLE OF OEB WORK FORMS AND CHAPTER 2 APPENDICES

| # | OEB Appendix Number | OEB Appendix Title | Location in Application or Reason not Provided |
|---|---|---|---|
| 1 | 2-A | List of Requested Approvals | Exhibit A, Tab 3, Schedule 1, attachment 1 |
| 2 | 2-AA | Capital Projects Table | Exhibit C2, Tab 2, Schedule 2 |
| 3 | 2-AB | Capital Expenditures | Exhibit C2, Tab 2, Schedule 3 |
| 4 | 2-AC | Customer Engagement Worksheet | Exhibit A, Tab 4, Schedule 1, attachment 1 |
| 5 | 2-BA | Fixed Asset Continuity | Exhibit C2, Tab 2, Schedule 1, attachments 1 to 6 |
| 6 | 2-BB | Service Life Comparison | Exhibit D1, Tab 6, Schedule 1 |
| 7 | 2-C | Year 1 Depreciation and Amortization Expense (Old CGAAP) | Exhibit D2, Tab 10, Schedule 1 |
| 8 | 2-D | Overhead Expenses | Exhibit C2, Tab 7, Schedule 1 |
| 9 | 2-EA | Account 1575 PP&E Deferral Account (2015 IFRS Adopters) | Not applicable. Decision with Reasons for proceeding EB-2011-0427, the OEB granted Remotes' request to use United States Generally Accepted Accounting Principles for regulatory purposes. |
| 10 | 2-EB | Account 1576 – Accounting Changes Under CGAAP (2012 Changes) | Not applicable. Decision with Reasons for proceeding EB-2011-0427, the OEB granted Remotes' request to use United States Generally Accepted Accounting Principles for regulatory purposes. |
| 11 | 2-EC | Account 1576 – Accounting Changes Under CGAAP (2013 Changes) | Not applicable. Decision with Reasons for proceeding EB-2011-0427, the OEB granted Remotes' request to use United States Generally Accepted Accounting Principles for regulatory purposes. |
| 12 | 2-FA | Renewable Generation Connection Investment Summary | Not applicable. Remotes customers are not eligible for the FIT program. See Exhibit B1, Tab 1, Schedule 1, Appendix G. |
| 13 | 2-FB | Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments | Not applicable. As Remotes is not connected to the grid, no renewable energy connections have qualified for this program. |

| # | OEB Appendix Number | OEB Appendix Title | Location in Application or Reason not Provided |
|---|---|---|---|
| 14 | 2-FC | Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments | Not applicable. As Remotes is not connected to the grid, no renewable energy connections have qualified for this program. |
| 15 | 2-G | Service Reliability Indicators | Exhibit A, Tab 5, Schedule 2, Attachment 1 |
| 16 | 2-H | Other Operating Revenue | Exhibit G2, Tab 2, Schedule 1 |
| 17 | 2-I | Load Forecast CDM Adjustment Workform | Not applicable. Remotes does not adjust the load forecast to account for CDM and will not be applying for an LRAM. |
| 18 | 2-1B | Actual and Forecast Load and Customer Data | Exhibit G2, Tab 1, Schedule 1 |
| 19 | 2-JA | OM&A Summary Analysis | Exhibit D2, Tab 3, Schedule 1 |
| 20 | 2-JB | Recoverable OM&A Cost Driver Table | Exhibit D2, Tab 3, Schedule 2 |
| 21 | 2-JC | OM&A Programs Table | Exhibit D2, Tab 3, Schedule 3 |
| 22 | 2-K | Employee Costs | Exhibit D2, Tab 5, Schedule 2 |
| 23 | 2-KA | OPEBs (Other Post-Employment Benefits) Costs | Exhibit D2, Tab 5, Schedule 3 |
| 24 | 2-L | Recoverable OM&A Cost per Customer and FTE | Exhibit D2, Tab 3, Schedule 4 |
| 25 | 2-M | Regulatory Costs Schedule | Exhibit D2, Tab 6, Schedule 1 |
| 26 | 2-N | Shared Services and Corporate Cost Allocation | Exhibit D2, Tab 4, Schedule 1 |
| 27 | 2-OA | Capital Structure and Cost of Capital | Exhibit E2, Tab 1, Schedule 1 (2013),<br>Exhibit E2, Tab 1, Schedule 2 (2018) |
| 28 | 2-OB | Debt Instruments | Exhibit F2, Tab 2, Schedule 1, Attachments 1 to 6 |
| 29 | 2-Q | Cost of Serving Embedded Distributors | Not applicable. Remotes has no embedded distributors. |
| 30 | 2-R | Loss Factors | Not applicable. Remotes has no approved loss factors. |
| 31 | 2-S | Stranded Meter Treatment | Not applicable. Remotes has no stranded meters. |
| 32 | 2-Y | Transition to MIFRS Summary Impact | Not applicable. Decision with Reasons for proceeding EB-2011-0427, the OEB granted Remotes' request to use United States Generally Accepted Accounting Principles for regulatory |

| # | OEB Appendix Number | OEB Appendix Title | Location in Application or Reason not Provided |
|---|---|---|---|
| | | | purposes. |
| 33 | 2-YA | One-Time Incremental IFRS Transition Costs | Not applicable. Decision with Reasons for proceeding EB-2011-0427, the OEB granted Remotes' request to use United States Generally Accepted Accounting Principles for regulatory purposes. |
| 34 | Previously 2-Z | Tariff of Rates and Charges at Current and Proposed Rates | Exhibit G2, Tab 3, Schedule 1, (Current) and Exhibit G2, Tab 3, Schedule 2 (Proposed) |
| 35 | Previously 2-W | Bill Impacts | Exhibit G1, Tab 5, Schedule 1 |

OEB COST OF SERVICE MODELS

| # | OEB Model Title Title | Location in Application or Reason not Provided |
|---|---|---|
| 36 | Revenue Requirement Work Form | Exhibit F2, Tab 1, Schedule 2 |
| 37 | Streetlight Cost Allocation Model | Not applicable. Remotes rates are set by regulation. |
| 38 | Income Tax/PILs Work Form | Exhibit D2, Tab 8, Schedules 2 and 3 |
| 39 | 2018 RTSR Work Form for Electricity Distributors | Remotes is exempt from the Retail Service Code |
| 40 | Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form | Remotes is not subject to the Board's CDM Code and does not have an LRAM |
| 41 | Capital Module Applicable to ACM and ICM | Remotes has not used the capital model in its IRM applications |
| 42 | Cost Allocation Model | Remotes rates are set pursuant to O. Reg 442/01 |
| 43 | Deferral and Variance Account (Continuity Schedule) Work Form | Remotes has only one Variance Account, the RRRP Variance Account. See Exhibit H for this information |

# EXECUTIVE SUMMARY OF APPLICATION

## 1.0 INTRODUCTION

Hydro One Remote Communities Inc. ("Remotes") is an integrated generation and distribution company licensed to generate and distribute electricity within twenty-one isolated communities in northern Ontario. Consistent with the Board's Decision in RP-1998-0001, Remotes is 100% debt-financed and is operated as a break-even company with no return on equity. This Exhibit and attached Schedules offer an overview of Remotes' business, its corporate vision, values and objectives, and the approvals it is seeking through this Application.

## 2.0 APPLICATION

Remotes is making this application in accordance with the requirements of the Ontario Energy Board *Filing Requirements for Transmission and Distribution Applications* issued November 14, 2006, and updated on July 20, 2017. The proposed revenue requirement and rates included in this Application have been prepared on the basis of a forward-looking 2018 test year.

Consistent with the Board's Decision in EB-2011-0427, Remotes uses US GAAP as its accounting standard.

## 3.0 REVENUE REQUIREMENT

Remotes is seeking approval of a revenue requirement of $56,689K: comprised of $17,612K from its customers (1.80% rate increase over 2017 rates), $999K from Other Revenues, and $38,078K from the Rural and Remote Rate Protection ("RRRP") fund for the 2018 test year. Other Revenues consist of external work, late payment and miscellaneous revenue. Higher revenues from external work in 2018 are expected to include assessments of Independent Power Authority distribution systems in Pikangikum and Wawakapewin and higher miscellaneous generation revenues reflect the anticipated large number of investments from Indigenous and Northern Affairs Canada ("INAC"). Calculation of the revenue requirement appears in the evidence at Exhibit F2, Tab 1, Schedule 1. Table 1 shows the breakdown of the revenue requirement and the change from the request made in proceeding EB-2012-0137 that used 2013 as the forward test year.

**Table 1**
**Breakdown of Revenue Requirement (in $K)**

| | Approved in EB-2012-0137 | In this Application | $ Change | % Change |
|---|---|---|---|---|
| Revenue Requirement | $52,284 | $56,689 | $4,405 | 8.4% |
| Recovered through rates | $17,260 | $17,612 | $352 | 2.0% |
| Recovered by other revenues | $514 | $999 | $485 | 99.4% |
| Recovered by RRRP | $34,510 | $38,078 | $3,568 | 10.3% |

## 4.0 OPERATIONS, MAINTENANCE AND ADMINISTRATION

Remotes' Operations, Maintenance and Administration ("OM&A") expenditures have been determined on the basis of an examination of required work programs to ensure that appropriate and cost-effective solutions are implemented. A description of Remotes' planning process is provided at Exhibit A, Tab 7, Schedule 3. The proposed OM&A expenditures are $50,143K and include $27,600K for diesel fuel required to generate electricity.

These expenditures are itemized at Exhibit D2, Tab 1, Schedule 1 and discussed in written direct evidence at Exhibit D1, Tab 1, Schedule 1 with an assumed inflation of 1.9%. The total compensation below includes all Regular staff.

**Table 2**

**Breakdown of OM&A Expenditures (in $K)**

| | Approved in EB-2012-0137 | In this Application | $ Change | % Change |
|---|---|---|---|---|
| OM&A | $43,483 | $50,143 | $6,660 | 15.3% |
| Fuel Costs | $24,067 | $27,600 | $3,533 | 14.7% |
| Total Compensation | $6,609 | $7,892 | $1,283 | 19.4% |

## 5.0 RATE BASE

Remotes' proposed Rate Base of $44,445K is discussed at Exhibit C1, Tab 1, Schedule 1.

Remotes has calculated working capital based on the formula-based methodology described in the Board's Filing Guidelines for Transmitters and Distributors issued July 14, 2017. The calculation of 2018 working capital, filed at Exhibit C2, Tab 5, Schedule 1, incorporates generation-related OM&A accounts as Remotes provides integrated generation and distribution services.

Depreciation expense for Remotes' submission for the 2018 revenue requirement is based on the methodology in an independent study conducted by Foster Associates in 2012 and approved in EB-2012-0137. Depreciation expense of $3,576K has been determined based on this study. These costs are described in written evidence at Exhibit D1, Tab 6, Schedule 1 and shown in detail in Exhibit D2, Tab 7, Schedules 1 and 2.

Remotes recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. Consistent with the Board Decision in EB-2012-0137, this regulatory asset is amortized consistent with the actual expenditures incurred each year. Remotes forecasts assessment and remediation costs of $1,032K in the 2018 Test Year. Land Assessment and Remediation is discussed in Exhibit D1, Tab 6, Schedule 1.

Major drivers of the capital expenditures in the Distribution System Plan ("DSP") include customer service requests, asset failure, assets at the end of their service life due to failure risk, system capacity, system reliability and operational efficiency and non-system physical plant, which are discussed at Exhibit B1, Tab 1, Schedule 1, Section 1.3. Remotes is proposing capital expenditures, net of contributed capital of $3,236K in the test year.

**Table 3**

**Rate Base and Net Capital Expenditures (in $K)**

| | **Approved in EB-2012-0137** | **In this Application** | **$ Change** | **% Change** |
|---|---|---|---|---|
| Rate Base | $41,090 | $44,445 | $3,355 | 7.5% |
| Capital Expenditures (Net) | $6,135 | $3,236 | ($2,899) | (47.3%) |

## 6.0 COST OF CAPITAL

Remotes is 100% debt-financed, consisting of 4% deemed short-term debt and 96% long-term debt. Remotes' evidence in support of its cost of capital appears at Exhibit E1, Tab 1, Schedule 1.

## 7.0 RURAL AND REMOTE RATE PROTECTION VARIANCE ACCOUNT

In accordance with standard regulatory practice, Remotes has incurred prior costs for which it is requesting approval in this submission. The December 2016 audited Rural and Remote Rate Protection ("RRRP") variance balance is $1,644K and is primarily related to increased diesel fuel costs and required maintenance. Remotes is proposing to recover $962K in the 2018 test year, which is the audited 2016 RRRP variance balance of $1,644K, offset by a 2017 income tax adjustment of $682K as described in Exhibit D1, Tab 7, Schedule 1, resulting in a total RRRP amount of $39,040K. Remotes' evidence regarding these account balances and proposed disposition appears at Exhibit H1, Tab 1, Schedule 1.

## 8.0 CUSTOMER RATE IMPACTS

Remotes is seeking approval for a 1.8% increase in customer rates for all its customer rate classes at all levels of consumption. Details on the proposed rate increase can be found in Exhibit G1, Tab 2, Schedule 1. Calculation of the rate revenue requirement appears in the evidence at Exhibit G2, Tab 3, Schedule 2.

**Table 4**

**Load Forecast Summary**

| | Approved in EB-2012-0137 | In this Application | Change | % Change |
|---|---|---|---|---|
| Load (MWhs) | 56,431 | 62,565 | 6,134 | 10.9% |
| Customer Numbers | 3,529 | 3,652 | 123 | 3.5% |

As discussed in Exhibit A, Tab 2, Schedule 1 and in the Summary of Remotes' Business attached as Schedule 2 to this exhibit, Remotes' customers do not pay rates based on cost. Rates are set based on rules prescribed by O. Reg 442/01. Remotes has not performed a cost allocation study and has not provided evidence related to cost allocation in this application.

## 9.0 BUSINESS CONTEXT

Most of Remotes' work is on reserve and the capital required to meet community load growth is funded by the federal government. Consequently, work is planned and executed in close collaboration with the First Nation communities, their Tribal Councils and Indigenous and Northern Affairs Canada ("INAC"). Further information on Remotes' service territory and these funding agreements can be found in Schedule 2 of this Exhibit.

The communities' isolation means that when the generating plant reaches its capacity, no new electrical load can be connected to the distribution system. Curtailing the connection of new houses and other community buildings can result in lower levels of customer satisfaction and a deterioration in service reliability and, if frustrated community members construct and connect unauthorized services to the distribution systems, can pose a serious risk to public safety. At the time of Remotes' last cost of service application in 2012 and during the intervening years, eight communities were in connection restrictions. Over the past five years, Remotes has worked with INAC and First Nation communities to address the need for community growth. Only one community is currently facing restrictions and a project is planned, starting in 2018, to remove the connection restriction in that community. The complexity of Remotes' funding arrangements and federal funding constraints requires planning flexibility as both the timing for funding approvals and amounts of funding available are uncertain. Further discussion of these funding agreements, the capital contributions expected from funded INAC during the Test Year and the subsequent years are discussed in the DSP filed at Exhibit B1, Tab 1, Schedule 1, Section 4.0. Investment summaries (business cases) associated with material capital projects are shown in Appendix A to that Exhibit.

Under the funding agreements Remotes is responsible for capital replacements and improvements that are not associated with load growth. As discussed above, Remotes is proposing capital expenditures, net of contributed capital of $3,236K in the test year. Evidence related to these expenditures is included in the DSP in Exhibit B1.

## 10.0 CUSTOMER ENGAGEMENT

Remotes' vision is to be a trusted partner to the communities it serves and has consequently established positive working relationships with its communities and customers. Projects, work in the community and electricity service are ongoing aspects of regular discussions with communities. Remotes believes that its proposed investments and the proposed rate increase respond to its customers' needs and preferences. Details on Remotes' engagement with customers and customer feedback from its most recent biennial survey can be found in Exhibit A, Tab 4, and in the supporting Schedules to that Exhibit. Further information on customer engagement and on coordinated planning with Third Parties can be found in the DSP, Sections 2 and 4.

## 11.0 PERFORMANCE MANAGEMENT

Information on Remotes' internal performance management can be found at Exhibit A, Tab 5, Schedule 1. Information on its historic service quality and reliability can be found at Exhibit A, Tab 5, Schedules 1 and 2, and also in Section 2.3 of the DSP, in Exhibit B1.

Over the past five years, Remotes has continued to implement several strategies to improve productivity, including a continued focus on coordination of work and flights to transport staff and equipment; more competitive fuel supply contracts; planning and purchasing processes to maximize winter road usage; improved project management; improved customer collections; and customer-focused renewable initiatives. As fuel continues to be Remotes' single highest cost, fuel management remains a key concern. As part of this application, Remotes is investing in maintaining fuel efficiency and in the building blocks needed to modernize an off-grid electricity system. Further information on Remotes' productivity initiatives can be found in Sections 2.1.2 and 2.3 of the DSP (Exhibit B1), in Exhibit A, Schedule 5 and Exhibit D1, Tab 1.

## 12.0 REMOTES BUSINESS PLAN

The Board of Directors of Remotes and Hydro One Inc. have approved the 2017 business plan on which this Application is based. An executive summary of the business plan is included as Exhibit A, Tab 3, Schedule 2, Attachment 1. The planning process and economic assumptions underlying the business plan are included at Exhibit A, Tab 7, Schedule 3. Remotes' governance and control framework and project approval and control framework are described in Exhibit A, Tab 7, Schedules 2 and 4.

## 13.0 SPECIFIC APPROVALS REQUESTED

This application seeks approval for a service revenue requirement of $56,689K for Remotes based on a 2018 test year. Calculation of the service revenue requirement can be found in Exhibit F2, Tab 1, Schedule 1.

Remotes is seeking approval for a 1.8% increase in customer rates for all its customer rate classes at all levels of consumption. Details on the proposed rate increase can be found in Exhibit G1, Tab 2, Schedule 1. Calculation of the rates revenue requirement appears in the evidence at Exhibit G2, Tab 1, Schedule 1.

Remotes is seeking approval for specific service charges as outlined in the proposed Rate Tariffs in Schedule G2, Tab 3, Schedule 2.

Remotes is seeking annual Rural and Remote Rate Protection of $38,078K. Calculation of this amount can be found in Exhibit G1, Tab 4, Schedule 1.

Remotes is seeking approval to recover $962K to recover the 2016 audited balance in the Rural and Remote Rate Protection Variance Account. This amount Remotes proposes to recover is comprised of the 2016 audited balance of $1,644K, less a 2017 adjustment for income tax of $682K explained in Exhibit D1, Tab 7, Schedule 1.

Remotes is also seeking approval to continue the Rural and Remote Rate Protection Variance Account to record differences between its costs and revenues. This is further discussed in Exhibit H1, Tab 1, Schedule 1.

These approvals requested can also be found in Exhibit A, Tab 3, Schedule 1, Attachment 1.

# Appendix 2-A
# List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

**is seeking the following approvals in this application:**

| | | |
|---|---|---|
| 1 | | This application seeks approval for a service revenue requirement of $56,689K for Remotes based on a 2018 forward test year. Calculation of the service revenue requirement can be found in Exhibit F2, Tab 1, Schedule 1. This request is made in accordance with section 78 of the Ontario Energy Board Act, 1998. |
| 2 | | Remotes is seeking approval for a 1.8% increase in customer rates for all its customer rate classes at all levels of consumption. Details on the proposed rate increase can be found in Exhibit G1, Tab 2, Schedule 1. This request is made in accordance with section 78 of the Ontario Energy Board Act, 1998.Calculation of the rates revenue requirement appears in the evidence at Exhibit G2, Tab 1, Schedule 1. |
| 3 | | Remotes is seeking approval for specific service charges as outlined in the proposed Rate Tariffs in Schedule G2, Tab 3, Schedule 2. This request is made in accordance with section 78 of the Ontario Energy Board Act, 1998. |
| 4 | | Remotes is seeking annual Rural and Remote Rate Protection of $38,078K. Calculation of this amount can be found in Exhibit G1, Tab 4, Schedule 1. This request is made in accordance with section 78 of the Ontario Energy Board Act, 1998. |
| 5 | | Remotes is seeking approval to recover $962 K to recover the 2016 audited balance in the Rural and Remote Rate Protection Variance Account. This amount Remotes proposes to recover is comprised of the 2016 audited balance of $1,644 K, less a 2017 adjustment for income tax of $682 K explained in Exhibit D1, Tab 7, Schedule 1. This request is made in accordance with section 78 of the Ontario Energy Board Act, 1998. |
| 6 | | Remotes is also seeking approval to continue the Rural and Remote Rate Protection Variance Account to record differences between its costs and revenues. This is further discussed in Exhibit H1, Tab 1, Schedule 1. This request is made in accordance with section 78 of the Ontario Energy Board Act, 1998. |

# SUMMARY OF REMOTES BUSINESS

## 1.0 INTRODUCTION

Remotes is an integrated generation and distribution company licensed to generate and distribute electricity within 21 isolated communities in northern Ontario (EG-2003-0138 and ED-2003-0037). A list of the communities served and a map of Remotes' distribution service territory can be found in Exhibit B1, Tab 1, Schedule 1, section 1.4.1. Remotes is 100% debt-financed and operates as a break-even business.

Remotes is driven by its corporate vision, mission and business values. Together, they provide the basis to deliver on targeted performance objectives.

### 1.1 Corporate Vision

"We will be a leading remote community generation and distribution utility measured on performance in safety, environment and customer loyalty".

### 1.2 Corporate Mission

"We are a remote community electrical generation and distribution company focused on customer satisfaction and on using management systems to achieve operational excellence."

### 1.3 Corporate Values

We value:

- Safe work environment
- Customers and community relationships
- Environmental sustainability
- Consistent, fair, treatment of customers and staff
- Financial responsibility and accountability
- Business integrity
- Employee engagement
- Innovation and continuous improvement

## 2.0 REMOTES' BUSINESS ENVIRONMENT

Remotes functions in a unique environment. Extremely low customer densities, a harsh climate, logistical challenges related to transportation, along with the absence of an integrated transmission system and complex funding arrangements with third parties, set Remotes apart from other Ontario electricity distributors. This unique operating environment has a profound impact on operations and costs throughout Remotes' service area.

The communities served by Remotes are isolated and are scattered across the far north of the Province. Thirteen communities are not accessible by year-round road and can be accessed only by aircraft, winter road or, in the case of one community, also by barge. The size and isolation of Remotes' service territory also means that the transportation and accommodation of staff, fuel, and equipment is a key driver of Remotes' costs. The use and viability of winter roads to reach these communities is a major cost variable within

Remotes' operations. If a winter road cannot be built in a given year, fuel costs, equipment costs and overall maintenance costs increase.

Industry, government and First Nations are currently examining the potential for the development in the remote north, including the development of a transmission grid. In 2010, the Ontario Government amended the *Electricity Act, 1998* (the "Electricity Act") to require Remotes to serve grid-connected communities in accordance with government regulation. The decision to permit Remotes to serve these customers was made to give geographically remote communities that are currently connected to the grid and those considering connecting to the grid the option of being served by an established electricity distribution company and in anticipation that these customers will qualify for rate protection if served by Remotes. Remotes has been working with the IESO, Wataynikaneyap Power ("Watay") and with Opiikapawin Services LP ("OSLP"), a limited partnership company to discuss grid connections, talk to communities served by Independent Power Authorities about service from a licenced distributor, and to help communities prepare for grid service. No new communities are expected to join Remotes' service territory before the end of 2018.

Remotes inherited Ontario Hydro's obligations to provide electricity to off-grid communities, which were originally negotiated with the federal and provincial governments. Under these arrangements, the federal and provincial governments funded the original capital installation of facilities. In First Nation communities, the arrangements with the federal government, through Indigenous and Northern Affairs Canada ("INAC"), remain in place. These Agreements specify that Remotes is responsible for funding ongoing operation and maintenance of the system and that INAC is responsible for funding capital related to system expansions and capital upgrades.

During the 1990s, INAC devolved its responsibility for community infrastructure to First Nation communities. INAC now transfers funding directly to First Nations, who are responsible for administering approximately 85 percent of the Department's program funds. As a result of these funding arrangements, the process for capital upgrades is complex and not completely within Remotes' control.

In 2011 INAC informed Remotes that no funding for generation upgrades was included in its 2012-2016 capital plan due to funding constraints. Because the isolation of the communities puts a hard cap on the services, the lack of funding led to community connection restrictions in eight communities. Following extensive engagements with INAC and local First Nations, INAC agreed to fund partial upgrades. Through this revised process, INAC pays Remotes to install a larger generator and to replace the engine auxiliary equipment as required. Several successful projects have been completed through this process. At this time, only two communities remain in connection restrictions. A project is currently underway in Kingfisher Lake to increase generation capacity and a project is planned to build a distribution line to connect Big Trout Lake and Wapekeka that will increase available capacity to Big Trout Lake. INAC funding for capital upgrades is discussed in more detail in the Distribution System Plan (Exhibit B).

## 3.0 DISTRIBUTION

Remotes operates nineteen isolated distribution systems to serve the twenty-one communities. Within each system, Remotes is responsible for transformation, voltage regulation, delivery and metering of power. Because the communities are far from each other, the distribution systems are isolated, distinct and stand-alone. These distribution systems operate at distribution voltages ranging from 4.16 kV to 27.6 kV.

The fixed distribution assets in service include approximately 242 kilometers of line and transformers distributed throughout the system, which are used for voltage transformation. Billing meters are used to measure energy consumption at customer supply points.

## 4.0 GENERATION

Due to the lack of grid connection, Remotes is a generator of electricity to meet its obligations under section 29 of the Electricity Act. Diesel generation is currently the prime source of electricity within the communities. Remotes also owns and operates two run-of-the-river mini-hydroelectric generating facilities and has four demonstration project windmills. The feasibility of using further renewable technologies is continually examined as new technologies evolve, but diesel is currently the most reliable and cost-effective technology.

There are presently 57 diesel generators in service, ranging in size from 60kW to 1500kW. Most stations have three generators, sized to meet community load at different times of the day. Automated operation ensures that the generation units are run to maximize fuel efficiency by matching the generator size to the community load. Depending on electrical demand, Remotes handles over 17 million litres of diesel fuel each year.

## 5.0 ENVIRONMENTAL MANAGEMENT SYSTEM

Remotes developed an Environmental Management System (“EMS”) in 1999 to help address a history of spills and to improve environmental performance. In the course of developing and implementing the EMS, Remotes has transformed itself into an environmental leader, recognized provincially and nationally for its environmental record. In 2001, Remotes was awarded the Canadian Council of Ministers of the Environment National Pollution Prevention award for small business in Canada. In 2002, Remotes achieved ISO 14001 registration of its EMS. In 2017, Remotes registered its system to the new ISO 14001-2015 standard, one of the first companies in Canada to achieve this milestone.

Remotes has achieved operating efficiency improvements through installation of automated Programmable Logic Controller ("PLC") controls, Supervisory Control and Data Acquisition ("SCADA") systems, upgraded engines and redesigned generating and fuel-handling software to support its PLC programs, all of which have resulted in improved efficiency, reduced use of diesel fuel and lower atmospheric emissions.

In 2003, Remotes developed and adopted an Emission Reduction Strategy and submitted an application and Action Plan for Reducing Greenhouse Gases to the Environment Canada Voluntary Challenge Registry (now known as "Clean Start"). Remotes continues to report, monitor and reduce its emissions.

## 6.0 GOVERNMENT REGULATION AND REMOTE COMMUNITY RATES

Remotes serves approximately 3,600 customers. Most customers within Remotes pay rates below the cost of service. Historically, rates for these Residential and General Service customers have been financially supported through a cross-subsidy from government customers within Remotes who historically have paid rates above cost (Standard A Rates), also through INAC capital contributions and Rural or Remote Rate Protection (RRRP). RRRP funding is currently set at $32,259K per year. This amount is funded through a $0.0003 per kWh charge to all grid-connected customers in Ontario that is set by the Ontario Energy Board to fund rate protection in rural and remote areas of the province.

# Executive Summary of Hydro One Remote Communities Inc. ("Remotes") Business Plan 2017 to 2022

| Remotes (USGAAP) $M | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| RRRP | $ 37 | $ 38 | $ 39 | $ 43 | $ 45 | $ 44 |
| OM&A | $ 48 | $ 50 | $ 52 | $ 57 | $ 59 | $ 60 |
| Capital Exp | $ 4 | $ 3 | $ 5 | $ 5 | $ 5 | $ 4 |

Hydro One Remotes generates and distributes electricity to customers in 21 off grid communities. It is 100% debt financed and is operated as a break-even company, with a net income of zero in all years over the budget period, with adjustments to the system wide RRRP to recover variances in net income each year.

Due to government regulation, customer rates are not set to cost. Most customers pay rates far below the cost of service. Customer rates are expected to increase by inflation each year through IRM applications, and by 4% through a COS application in 2018.

## Corporate Vision

"We will be the leading electrical utility and a trusted partner to remote communities in Ontario's north."

## Corporate Mission

"We supply safe, reliable and affordable electricity to remote communities by focusing on continuous improvement, operational excellence and outstanding customer service."

## Business Context

Fifteen of the communities we serve are First Nation communities, isolated and scattered across Ontario's far north. The communities are economically disadvantaged. Most work is on reserve and the capital required to meet community load growth is funded by the federal government. Consequently, work is planned and executed in close collaboration with the First Nations communities, their Tribal Councils, and Indigenous and Northern Affairs Canada (INAC). We involve First Nations in our business as employees, contractors, local operators[1] and meter readers. Most of our suppliers are First Nation enterprises or have a First Nation component to

[1] Operators: Employees of the First Nation Band Council who perform minor maintenance in Remotes' generating stations.

their business. We listen to our customers through community meetings, consultations with Chiefs and Band Councils and our Customer Advisory Board.

The communities we serve are named in provincial legislation. The provincial government has received requests from Cat Lake, Pikangikum and Wunnumin to join Remotes' service territory. Revenues and costs to service these communities are built in to the business plan in 2018, 2019 and 2020 respectively.

## Major Initiatives

The isolation of our communities means that when generation limits reach capacity, no new electrical services can connect to the distribution system. Federal funding constraints led to connection restrictions in eight communities. To overcome this problem, we developed a collaborative process with the federal government and local First Nations to fund incremental upgrade projects, that reduce federal costs allowing for federal investment in a greater number of projects, defer the need for Remotes investments in capital and maintenance, and allow communities to grow. Two major upgrade projects are planned over the period, a fully recoverable project in Kingfisher Lake and a multi-year tie line between the communities of Wapekeka and Big Trout Lake. Once these projects are complete all eight constrained communities will be able to grow. We plan to monitor and measure the net benefit of the 2017 Kingfisher Lake project to ensure that the project is on time, on budget, and that the maximum benefit to the community of Kingfisher Lake and to ratepayers is realized.

We are engaging in a multi-year project to replace our SCADA/PLC systems over the plan period. The investments in SCADA/PLC and in telecommunications will improve our ability to diagnose system issues, improve reliability and, potentially, reduce costs by avoiding flights and field visits.

We handle over 17 million litres of fuel each year. Remotes' Environmental Management System (EMS) has been registered to the ISO standard since 2002 and has driven a culture of continuous improvement throughout the business. We integrated our safety management into our EMS in 2006 and have reduced safety risks and improved our overall safety performance as a result. In 2017, we plan to register our EMS to the new ISO standard. We monitor, measure and report our environmental performance, especially with regard to spills. We also monitor, measure and report our employee and public safety performance.

We are collaborating with Ontario Power Generation and the Gull Bay First Nation to develop a solar/battery micro grid in Gull Bay. The project is expected to be in-service in 2018 and to reduce our greenhouse gas emissions, in response to government policy.

## Efficiency and Productivity Measures

Fuel is our largest single cost. We expect to save $1.2 million annually ($7.2 million over the plan period) in fuel costs by focusing on winter road transportation and fuel purchase/storage agreements with local First Nations.

## Customer Measures

Because most of our customers are First Nations, strong relationships are key to our success. We measure and report the number of meetings the Managing Director has with Band and Tribal Councils.

We hire an independent research company to perform a biennial telephone survey of customer satisfaction. Our target for 2017 is to retain a satisfaction level of 90%.

# RENEWABLE ENERGY REINDEER PROGRAM

## 1.0 INTRODUCTION

Customers in Remotes' service territory are committed to environmental protection and are interested in developing renewable energy resources to replace diesel generation in their communities. Remotes developed a small renewable energy program called the REINDEER (**R**enewable **E**nergy **IN**novation **D**i**E**sel **E**mission **R**eduction) Program that allows customers to generate electricity and sell it to Remotes based on the avoided price of diesel fuel.

## 2.0 REINDEER PROGRAM

In OEB proceeding EB-2008-0232, the Board accepted Remotes' proposal to establish a program to purchase electricity from renewable energy based on the avoided cost of diesel fuel. Due to the high cost of construction in the north and a lack of experience developing renewable resources, few First Nations were initially able to take advantage of the program. In 2011, the federal government began offering First Nations and their private sector partners, ECO-Energy grants to install photo voltaic panels. The provincial government established policies to encourage Indigenous involvement in the electricity sector, building knowledge and experience. The IESO and the federal government also began funding community energy plans that allowed communities to develop energy plans within their own communities, including assessing options for alternative sources of energy. The IESO also assisted the three First Nation communities that are not included in the Remote Community Connection Plan to assess renewable technologies that will help the communities reduce diesel usage.

In response to growing interest from communities in developing renewable generation, Remotes developed a Standard Guideline for the program. The integration of renewable energy into isolated distribution systems must be carefully managed to ensure that the electricity is controlled and power quality maintained for end-use customers. To limit the time and cost required for engineering review of each project, the guideline establishes sizes based on the smallest diesel generator in each community. This approach ensures that electricity can be controlled by the diesel generation ensuring end-use power quality and also limits the cost to review each application. Larger projects require addition engineering design to ensure safe, reliable electricity in the communities.

First Nations and their partners expressed concerns about the volatility of diesel fuel costs and the need to have some price stability to get private sector loans. In response to these concerns, Remotes decided to calculate and offer the community specific avoided cost of diesel fuel based on a three year rolling average. This approach is administratively simple and is based on audited values for fuel, reflects the actual cost in each community and reduces price volatility for developers.

As a result of these efforts and government funding to support projects in the north, communities have now started to take advantage of the program. Eleven small net metering projects (10kW-110kW) are currently in place and four 10 kW solar power purchase agreements are also in place.

Medium to high penetration projects are planned in the three First Nation communities that the IESO does not expect to connect to the grid, Fort Severn, Gull Bay and Whitesand (Armstrong). Gull Bay First Nation (Kiashke Zaaging Anishinaabek) is working with Ontario Power Generation and other collaborators on a Photo Voltaic solar installation with battery storage and controller. The project is currently in the design stages and is supported by grants from the Ministry of Energy. Whitesand First Nation is planning an ambitious project to develop a pellet plant to make use of its forest resources, along with a large cogeneration project that will provide steam and electricity to the plant and electricity to the communities of Whitesand, Collins and Armstrong. The project has benefitted from federal funding for studies and project initiation. The proposed project is 4 MW and too large for Remotes' REINDEER program. The Minister of Energy directed the IESO to enter into a 20 year agreement to purchase electricity from the cogeneration project to service community load. The IESO was also directed to pay for the electricity sold to the pellet plant. Remotes has provided technical assistance to the project and expects to assist the IESO and Whitesand with settlement and to purchase the electricity related to the community load from the project based on the price of diesel fuel once the project is built. Last year, the IESO and Whitesand entered into an agreement related to this direction. Given the complexity of the project, Whitesand First Nation has up to ten years to build the project and put it into service. Detailed design and construction of the project has not started. None of the larger projects are expected to be in service within the test year (2018). The REINDEER Standard Guideline and other materials describing the program in detail are shown at Exhibit A, Tab 3, Schedule 3, Attachments 1 and 2.

Remote Communities Inc.

# Hydro One Remote Communities Inc. **R**enewable **E**nergy **IN**novation **D**i**E**sel **E**mission **R**eduction (**REINDEER**) Guideline – (Effective March 23, 2017)

## 1.0 Background

Hydro One Remote Communities Inc. (Remotes) is a subsidiary of Hydro One Inc. From its service centre in Thunder Bay, Ontario, provides energy services primarily through diesel generation to approximately 3500 customers in 21 remote northern communities that are not connected to the provincial electricity grid.

The Independent Electricity System Operator (IESO) FIT or MicroFIT program does not currently extend to Remotes' service territory. Potential REINDEER providers are encouraged to review both IESO programs at www.ieso.ca as they may be better suited to participant needs.

Remotes is interested in enabling the connection of renewable energy projects to reduce the impact of diesel fuel on the environment within its service territory. The Remotes' **R**enewable **E**nergy **IN**novation **D**i**E**sel **E**mission **R**eduction (REINDEER) program was developed for projects of this nature. The REINDEER guidelines are provided below.

## 2.0 REINDEER Guidelines:

There are two (2) types of REINDEER projects: The "Standalone" type project and the "Net Metering" type project. The "Standalone" projects will get paid for production, while the "Net Metering" projects will receive a reduced monthly bill, and in some situations a credit that expires after 12 months. The standard general guidelines for a REINDEER project as well as the details of the two types of connections are outlined hereafter.

### 2.1 Standard General Guidelines:

- REINDEER provider builds, owns, operates and maintains all assets up to and including point of connection to Remotes' distribution system.
- Hydro One Remotes provides connection access to the distribution system or generation station as applicable provided that the REINDEER project meets technical and metering specifications.
- Remotes' service reliability, customer power quality and existing assets must not be negatively impacted by the connection of the generation facility.
- REINDEER projects must be sized according to the electricity needs of the community and according to the kW size of the existing generation in the community.
- Hydro One Remotes reserves the right to determine the connection point and configuration to its distribution system.
- Contract is terminated when the distribution system is connected to the transmission grid. Proponents should contact the OPA for pricing and eligibility for OPA grid connected power purchase programs.
- 10 year term, renewable thereafter in 5 year contracts.
- Consultation with First Nation communities may be required as directed by Hydro One Remotes.
- All projects must meet the technical requirements set out in Sections 6.2.25, 6.2.26 and 6.2.27 of the Distribution System Code.

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**680 Beaverhall Place**
**Thunder Bay ON P7E 6G9**
**Toll Free: 1-888-825-8707**
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**www.HydroOne.com**

- All projects are subject to a technical review. The proponent is responsible for paying for the cost of this technical review. Generally, larger projects will require a more comprehensive engineering review.
- REINDEER project providers must enter into a connection agreement with Remotes.
- All contracts are subject to legal review and must be approved by President& C.E.O. of Hydro One Remotes.

## 2.2 Standalone Projects:

Hydro One Remotes considers a project a “Standalone” type project if the installation’s primary purpose is to provide additional generation to the community and will feed all of the power produced into Remotes’ system.

Remotes offers to pay the 3 year historical average cost of fuel per kWh produced/avoided cost of fuel specific to that community. The proposed rates as of January, 2017 (based on 2014-2016 annual data) are as follows. All amounts will be paid to the provider quarterly.

| REINDEER Standalone Rates 2017 | |
|---|---|
| **Community** | **$/kWh** |
| **ARMSTRONG** | 0.230 |
| **BEARSKIN** | 0.397 |
| **BIG TROUT (KI)** | 0.437 |
| **BISCO** | 0.346 |
| **DEER LAKE** | 0.395 |
| **FORT SEVERN** | 0.667 |
| **GULL BAY** | 0.277 |
| **HILLSPORT** | 0.364 |
| **KASABONIKA** | 0.403 |
| **KINGFISHER** | 0.376 |
| **LANDSDOWNE** | 0.342 |
| **MARTEN FALLS** | 0.476 |
| **OBA** | 0.356 |
| **SACHIGO** | 0.372 |
| **SANDY LAKE** | 0.388 |
| **SULTAN** | N/A[1] |
| **WAPEKEKA** | 0.484 |
| **WEAGAMOW** | 0.342 |
| **WEBEQUIE** | 0.406 |

[1] Standalone Projects not required in Sultan

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Hydro One Remotes recognizes that its operating environment is unlike any other and the above guideline may not match the unique circumstances of each situation.

As such:

- Hydro One Remotes is willing to commit labour and equipment resources, to install, operate and maintain any Standalone project, provided that the offered rate is reduced accordingly.
- Hydro One Remotes will NOT provide up-front financing or capital contribution at this time.
- Hydro One Remotes will also consider asset purchase clauses, during or at expiry of the contract term.
- Preference is given to proven technology. Remotes may consider research or innovation projects provided the contract terms are adjusted accordingly. Hydro One Remotes reserves the right to assess each project on its own merit and may consider variations of standard terms, provided regulatory and business requirements are met.
- Hydro One Remotes reserves the right to withdraw this guideline at any time.

## 2.3 Net Metering Guideline

Hydro One Remotes encourages proponents to consider working with First Nations to develop Net Metering projects as an alternative to Standalone generating projects. Net Metering enables customers to generate their own electricity to reduce the per kWh cost of electricity paid to Hydro One Remotes.

In order for a project to be considered a Net Metering project, the electricity must be generated primarily for use within the metered facility and meet the following criteria:

1) Electricity must be generated from a renewable source.
2) Projects must be sized according to the facility's load and may not exceed 50% of the current annual energy consumption.
3) Project must be sized according to the current locations electrical service capacity. Remotes will not modify the current electrical service to accommodate the renewable technology.

An engineering review of the connection is required in order to qualify for connection to Hydro One Remotes' distribution system and for the purchase of stand-by power from Hydro One Remotes.

From time to time, Net Metering projects may send excess generation into Hydro One Remotes' distribution system. Hydro One Remotes will credit the customer's bill for this excess electricity. The bill credits for electricity beyond the customer's own needs will expire after 12 months.

## 2.4 Additional Notes

Potential REINDEER providers looking for additional information are to contact Customer Service Department, Hydro One Remote Communities Inc. at 807-474-2805 or RemotesCustomerService@HydroOne.com.



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Exhibit A-03-03
Attachment 2
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# REINDEER RENEWABLE ENERGY PROGRAM
## @Hydro One Remotes

- **Must use a renewable resource**
- **Must have First Nation participation/support (if in a First Nation community)**

## TWO TYPES OF RENEWABLE PROJECTS AVAILABLE

- **Project must be sized according to the electrical needs of the community and to the kW size of existing generation in the community**

### “Net” Metering

- Production of renewable energy “nets” or offsets building energy use
- Customer/owner enjoys lower energy bills
- Currently a typical net metering installation is on a Standard ‘A’ Community-owned building (school, water treatment plant, etc.) as these buildings offer the highest rates

As of May 1, 2016, over 250 kWh:
- Air Access – 97.69 cents/kWh
- Road/Rail – 67.56 cents/kW

- Projects must be sized according to the facility’s load and may not exceed 50% of annual energy consumption

### Stand-alone

- Payments are made for kWh injected into Remotes’ system
- kWh rate is based on 3 year historical average cost of fuel per kWh (avoided cost of fuel) specific to that community
- 2016 rates range from 24.8 cents/kWh to 70.7 cents/kWh with most communities in the 40 cent range
- Customer/owner gets paid quarterly

**FOR MORE INFORMATION CONTACT REMOTES CUSTOMER SERVICE AT 1 888 825 8707 OR RemotesCustomerService@HydroOne.com**

# CUSTOMER SERVICE AND ENGAGEMENT STRATEGY

## 1.0 INTRODUCTION

The communities Remotes serves are small and isolated, scattered across roughly half of Ontario's land mass. Fifteen of the communities are First Nations reserves, and the other six are provincial communities, located mainly along the national rail lines. The smallest communities have fewer than forty customers, the largest just over five hundred. The communities' isolation limits economic opportunities for residents. Most of Remotes' customers are economically disadvantaged and are low income. Unemployment is high and, for community members in the work force, employment opportunities are mainly part-time or seasonal. The inaccessibility of the communities means that the cost of goods for residents is high. Gasoline, construction materials for homes, cars and groceries must all be transported over winter roads or by plane. Remotes' customers continue to have a close attachment to the land, and rely on the traditional spring and fall hunts for much of their food.

Remotes' vision is to be a trusted partner to these communities, taking account of local priorities, listening to customers, and treating customers with sensitivity and flexibility. Remotes operates in all of the communities it serves at their request and believes that all of its communities have a choice of service provider, a belief demonstrated by the large numbers of Independent Power Authorities operating in the north. Consequently, Remotes works hard to establish and maintain long-term relationships with Band Councils, customers and other stakeholders.

## 2.0 WORKING RELATIONSHIPS WITH BAND COUNCILS

Customers living on reserve comprise the majority of Remotes' customer base, about 87% of total customers. Remotes' Managing Director and other employees meet regularly with Band Councils and Band Administrators both in Thunder Bay and in the communities. Field staff stop by the Band Office to visit when they are on site and Band Councils are notified when crews will be in the community for planned work. Remotes' staff also talk to Band Council members and staff regularly by phone. By working closely with Band Councils and by establishing positive working relationships, Remotes hears about community needs and also helps communities understand what to expect in terms of reliability, customer, work program execution and programs for customers.

In First Nation communities, capital projects related to load growth are undertaken collaboratively with the Band Council, as the projects are funded and conducted only if requested by the First Nations. As part of planning for local and electrical infrastructure, Remotes meets with Band Councils to discuss peak load and the likely timing when an upgrade would be required, if the community is approaching restrictions. To forecast load and fuel deliveries, Remotes talks to Band Councils to understand community plans for housing and other infrastructure. Regular engagement also includes discussion on power outages including the root causes of events, discussions on fuel purchases and fuel levels at the plants, and discussions about the kind of work that is planned and required in their communities.

As permitted by Section 13.2(d) of its Distribution licence, Remotes works closely with local Band Councils when planning and undertaking collection trips. Working with the Band Council is required, as Band Councils have the legal right to bar outside parties from reserve. Working closely with the Band Council also ensures that customers have opportunities and time to access available community support and OEB programs such as the Low-Income Emergency Assistance Program (LEAP) and the Ontario Electricity Support Program (OESP), and so that the local government can advise Remotes of sensitive situations such as Elders or cases of particular hardship. Remotes believes that its collection practices respond to the needs of Band Councils and its customers.

Remotes also works with Band Councils on customer service issues. Remotes ensures that customers are set up correctly and recorded accurately in the Customer Information System by liaising with the local Band Council staff. This practice ensures that customers who are eligible for HST exemption benefit from that exemption and the First Nation Delivery Credit. It also helps to ensure that customer data is kept up-to-date if customers move.

Remotes' customers have a connection to the land and see environmental protection as a priority. Remotes understands this priority and made a commitment to reducing the impact of its operations on the environment. In 2017, Remotes registered to the new, rigorous, ISO 14001-2015 standard. Remotes invests in plant improvements to reduce the risk of spills, to reduce the severity of spills by investing in spill-alarm systems and to remediate contaminated lands. Projects to remediate lands require First Nations support and commitment. If available, equipment and materials such as gravel or biocells are rented or purchased from the First Nations. Remotes plans these projects with Band Councils and works together with them to carry them out.

## 3.0 SUPPORTING THE LOCAL ECONOMY

From discussions with customers and Band Councils, Remotes sees and hears the need for economic development in the north and tries to address this need as part of the way it conducts business. First Nations are involved in Remotes' business as employees, contractors and labourers. Most suppliers are First Nation enterprises or have a strong

First Nation component to their businesses. To take advantage of cost savings related to winter road transportation and to improve opportunities for local businesses, Remotes enters into mutually beneficial contracts to purchase fuel from five First Nations-owned fuel storage tank farms.

Given the inaccessibility of Remotes' service territory and the cost to transport staff and equipment, Remotes relies on local community members to work in its plants, respond to emergencies and read meters. Remotes' operators, in particular, are eyes and ears on the ground, offering information and advice on a wide range of community and customer issues. Operators have enormous responsibility for the safety and reliability of the electrical systems. Remotes' operations team work closely with these community members to train and support them in their day-to-day work.

As part of conservation programs established by the federal government and IESO, many communities Remotes serves undertook Community Energy Plans. Through these plans, communities identified renewable energy development opportunities. Remotes' REINDEER program (**R**enewable **E**nergy **IN**novation **D**i**E**sel **E**mission **R**eduction) was established to respond to the desire of its customers to reduce diesel use in their communities and to create opportunities for First Nations to share the economic benefits of renewable energy projects. Remotes' most recent customer survey shows that 64.7% of Remotes customers support investments in renewable energy (Exhibit A, Tab 4, Schedule 1, Attachment 3). Fifteen small customer-owned installations are now in service. Further projects are also planned and are discussed in Exhibit A3, Tab 3, Schedule 3 and in the DSP.

## 4.0 ENGAGEMENT WITH END USE CUSTOMERS

From time-to-time, Remotes holds community meetings with end-use customers. These meetings can be discussions of a project, a general information session about services or a celebration of a completed project such as a generation upgrade. Remotes also offers presentations to schools (about two a year) when staff are in the community doing other work, to teach local children about electrical safety. Remotes also participates in career fairs in the north to inform students about opportunities in the electrical field.

Remotes has a Customer Advisory Board (CAB) that usually meets twice a year. Starting in 2006, the CAB has offered advice from the perspective of ordinary residential and business customers on a wide range of business activities, including improvements to operator and meter reader training, job opportunities in the electrical field, expansions to the operator role (operator switching), conservation programs, ways to increase renewable energy use, reliability improvements, the need for celebrations of new generation projects/opportunities for community members to see inside generating stations, and the real life impact of customer connection constraints. The CAB has had a positive impact on Remotes' business, in particular, on training programs for local operators and meter readings, on the decision to train and qualify operators to perform switching, and on the integration of renewable energy resources. Further information on CAB engagement sessions is included in Exhibit A, Tab 4, Schedule 1, Attachment 1.

Remotes surveys its customers once every two years to determine overall customer satisfaction with its services and to get feedback on programs. Remotes uses a few of the survey questions to ask about specific ways that service can be improved and to identify customer knowledge of available programs and services. Based on the survey results, action plans are developed to ensure services reflect customer expectations and improve customer knowledge of programs such as LEAP and OESP are in place.

Further information about Remotes' outreach to customers and, in particular, about customer feedback on priorities, can be found in Exhibit A, Tab 4, Schedule 1, Attachments 1, 2, and 3, and in the Distribution System Plan, Sections 2 and 4.

# Appendix 2-AC
# Customer Engagement Activities Summary

| Provide a list of customer engagement activities | Provide a list of customer needs and preferences identified through each engagement activity | Actions taken to respond to identified needs and preferences. If no action was taken, explain why. |
|---|---|---|
| **Customer Advisory Board (CAB) Meetings**<br><br>The Customer Advisory Board is comprised of residential and commercial customers from fly-in and road rail communities.  The CAB has been in place since 2006 and offers ongoing advice to Remotes on service improvements and initiatives. The CAB itself largely determines what aspects of Remotes work to be discussed but Remotes also uses the CAB as a sounding board for the implementation of new initiatives and programs. Discussion items and concerns are regularly raised by the CAB on a wide variety of service issues. | **Renewable Energy**<br>1. Reduction of diesel is better for the environment. Remotes should reduce diesel usage by increasing renewable energy<br><br>2. Local renewable initiatives, e.g. Whitesand, Gull Bay, Deer Lake | **Renewable Energy**<br>1. Developed renewable energy program to allow customer-owned generation to connect to the system. Discussed program design with the CAB, including net metering.<br><br>2. Connected 15 customer-owned solar projects and working with three communities on deeper integration. Working with Gull Bay and Whitesand on proposed projects. |
| | **Rates/Affordability**<br>Process for setting rates in Remotes' Service territory; Standard A versus Non Standard A Rate Classifications and difference in rates. CAB noted concerns that Standard A rates are too high. | **Rates/Affordability**<br>Allowed net metering on Standard A accounts. Established conservation programs that are available to Standard A customers. |
| | **OESP & LEAP**<br>Customer outreach, importance of contact with Social Services and Band Councils in communities | **OESP & LEAP**<br>Information included in bill inserts, letters to customers, letters to Chief and Council, Tribal Councils and Social Services in communities |
| | **Safety**<br>1. Public Safety hazards overview<br>2. Need to engage youth<br>3. Importance of ESA inspections | **Safety**<br>Radio ads on public safety<br>School presentations<br>Discussion/information on ESA to Band Councils/other residents |

| Provide a list of customer engagement activities | Provide a list of customer needs and preferences identified through each engagement activity | Actions taken to respond to identified needs and preferences.<br>If no action was taken, explain why. |
|---|---|---|
| | **Billing**<br>1. Inaccurate bills: estimates, in particular for seasonal customers<br>2. Inaccurate bills: meter reader errors | **Billing**<br>1. Working toward fewer estimated bills for seasonal customers, but access to seasonal properties can be an issue<br>2. Improved training for meter readers<br>3. Moved to digital meters |
| | **Local Training/Employment**<br>1. High unemployment in communities and the need for more opportunities for community members in electricity sector | **Local Training/Employment**<br>1. Hydro One now supports a pre-apprenticeship program at Confederation College to improve access for First Nation members seeking to enter apprenticeship programs. Remotes toured its communities to let customers know about the program and its benefits<br>2. Remotes now participates in career fairs at local schools |
| | **Generation Constraints**<br>1. Houses in Deer Lake cannot connect<br>2. Communities not able to grow<br>3. Concerns about INAC funding constraints | **Generation Constraints**<br>Because of the isolation of the communities, when load grows beyond the generation station capacity, communities are unable to connect new services to the distribution system. INAC did not have funding to increase generation and connections of new services were restricted in eight communities. Remotes developed a process with INAC and First Nations for incremental generation upgrades to relieve supply constraints in communities. Since developing this approach, upgrades were made in six communities, with two more planned |

| Provide a list of customer engagement activities | Provide a list of customer needs and preferences identified through each engagement activity | Actions taken to respond to identified needs and preferences.<br>If no action was taken, explain why. |
|---|---|---|
| | **Customer New Connections**<br>1. Band Councils pay for the housing construction and new connections. The CAB suggested an allocation of costs to Residents through rates. | **Customer New Connections**<br>No change. Under the federal-provincial funding agreements with INAC, new customer connections are a federal responsibility. Increases to Remote customer rates are set by regulation |
| | **Reliability**<br>1. An unplanned distribution outage due to a house fire resulted in the cancellation of the Santa Claus parade in a community. Operators should be able to respond to these issues.<br>2. Unplanned generation outages | **Reliability**<br>1. Developed training program for operators to become qualified under the Electrical Safety rules so that they can respond to certain line outages. Program also has the benefit of reducing trouble costs.<br>2. Several investments are proposed to maintain generation reliability |
| | **Environment**<br>1. Spills response<br>2. Spill events<br>3. Environmental Management System | **Environment**<br>1. Remotes gave a presentation on management of spills, training for spills response, the installation of spill alarms and other initiatives to reduce the environmental footprint. |
| **Band Council Engagement**<br><br>**Regular, Ongoing Meetings, Emails, Letters, Phone Conversations. Engagement is grouped under major topics.** | **Discussions/Engagement with Work Activities:**<br>1. Connections, collections, work in community<br>2. Winter road conditions: Update<br>3. Environmental – Site remediation<br>4. Community emergencies and interruptions | **Discussions/Engagement with Work Activities:**<br>1. Work with First Nations to set schedule for activities in the communities and to respond to service requests<br>2. First Nations build and operate winter roads<br>3. First Nations are partners in site remediation projects<br>4. Notify First Nations and discuss root causes of unplanned outages |

| Provide a list of customer engagement activities | Provide a list of customer needs and preferences identified through each engagement activity | Actions taken to respond to identified needs and preferences.<br>If no action was taken, explain why. |
|---|---|---|
| | **Discussions/Engagement Economic Development/Partnership Opportunities**<br>1. Renewables – Desire to be involved<br>2. Gravel—purchase arrangements<br>3. Winter road tolls—pricing for use of road<br>4. Equipment rental—availability, rates<br>5. Temporary labour—opportunities for community members<br>6. Meter reading—contract negotiation<br>7. Operators—contract negotiation<br>8. Forestry line clearing—opportunities, timing<br>9. Fuel purchase agreements | **Discussions/Engagement Economic Development/Partnership Opportunities**<br>1. Established REINDEER program<br>2. Gravel is purchased from the First Nations<br>3. Remotes pays First Nations for the use of winter roads<br>4. Remotes rents equipment from the First Nations<br>5. Remotes hires local members to work on projects<br>6. Meter readers are community members, employed by the First Nation<br>7. Operators are community members, employed by the First Nations<br>8. Remotes contracts brush work to the First Nations<br>9. Remotes purchases fuel from First Nations who have fuel storage facilities in communites |
| | **Discussions/Engagement on community planning**<br>1. Planned housing<br>2. Community energy overview, load, peak, assets<br>3. Energy forecast and housing, community development | **Discussions/Engagement on community planning**<br>Annually, Remotes works with First Nations on forecasting electrical requirements |

| Provide a list of customer engagement activities | Provide a list of customer needs and preferences identified through each engagement activity | Actions taken to respond to identified needs and preferences.<br>If no action was taken, explain why. |
|---|---|---|
| **Wataynikaneyap Power Project**<br>Wataynikaneyap Power is a transmission company owned by twenty-two (22) First Nations and Fortis Ontario. Nine (9) of the communities Remotes serves are owners and partners in this project. Remotes has worked with the project developers to ensure that communities are prepared for grid connection. | **Topics/Preferences/Needs**<br>1. Distribution Assets meet safety and operational standards<br>2. Backup power related to line outages<br>3. Economic development opportunities<br>4. Information licensing, rates, regulation<br>5. Information on services to Independent Power Authorities | 1. Asset assessments undertaken with the Electrical Safety Authority<br>2. Participated in IESO and Watay led discussions<br>3. Offered information about apprenticeship opportunities, educational programs<br>4. Informed customers and IPAs of OEB/ESA and other rules<br>5. Attended Chief & Council/community meetings in four IPA communities and several planning workshops including all IPA communities in Sioux Lookout and Thunder Bay |

# The Opiikapawin Services LP,

# Hydro One Remote Communities Inc.,

# and

# Ontario Energy Board

# Watay Community Workshop

**Date: November 23 and 24, 2016**

**Location: Sioux Lookout**

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# Summary of Workshop

On November 23-24, 2016 a two day workshop was held in Sioux Lookout with seven remote First Nation communities that are currently served by Hydro One Remotes. These seven communities are also part of the Watay Power project which is comprised of twenty-two First Nation communities that have majority ownership of the project. The seven communities are Bearskin Lake First Nation, North Caribou Lake First Nation, Kingfisher Lake First Nation, Kasabonika Lake First Nation, Sachigo Lake First Nation, Kitchenuhmaykoosib Inninuwug First Nation, and Wapekeka First Nation. The purpose of the workshop was to have discussions with the Hydro One communities that would be connecting to the provincial grid to provide information and identify issues and concerns. Hydro One Remotes provided a lot of information to the participants with regards to their operations.

On Day 2, OEB staff made a presentation on behalf of the Ontario Energy Board regarding the Development of a First Nations Rate for On-Reserve First Nations Electricity Customers as directed by the Minister of Energy. After the presentation the community participants (three from each First Nation) divided into three groups and provided feedback on issues within their communities regarding electricity cost and service and on the proposed First Nation Energy Rate and the ability of First Nation band members to pay their hydro bills.

A high level summary of those discussions is as follows and represents the feedback transcribed from the flip charts from the community participants that were in attendance. The information on the “flip chart” summary is from the discussions with the participants after the OEB presentation. There is information referencing the OEB presentation as well as the information provided by Hydro One Remotes. This information was gathered in an informal group setting and has not been altered.

# Attendance

| | |
|---|---|
| Kevin Mann | Hydro One Remote Communities Inc. (Remotes) |
| Laura Sayers | Shibogama First Nation Council |
| Elijah Begg | Kingfisher Lake |
| Noah Chapman | Kitchenuhmaykoosib Inninuwug First Nation (KI/Big Trout Lake) |
| David Jeremiah | North Caribou Lake First Nation (Weagamow) |
| Ernest Quequish | North Caribou Lake First Nation (Weagamow) |
| Dan Chikane | North Caribou Lake First Nation (Weagamow) |
| Mitchell Diabo | Kasabonika Lake First Nation |
| Vincent Ostberg | Bearskin Lake First Nation |
| Robert Kamenawajamin | Bearskin Lake First Nation |
| Lott Sainnawap | Kingfisher Lake First Nation |
| Isaac Sainnawap | Kingfisher Lake First Nation |
| Linda Kamenawatami | Bearskin Lake First Nation |
| Charlie Barkman | Sachigo Lake First Nation |
| Brian Thunder | Sachigo Lake First Nation |
| Mandy Wirta | Indigenous and Northern Affairs Canada (INAC) |
| Kraemer Coulter | Hydro One Remote Communities Inc. (Remotes) |
| Oli Laskujarvi | Hydro One Remote Communities Inc. (Remotes) |
| Ralph Falcioni | Hydro One Remote Communities Inc. (Remotes) |
| Una O’Reilly | Hydro One Remote Communities Inc. (Remotes) |
| Josie Anderson | Kasabonika Lake First Nation |
| Geoffrey McKay | Kitchenuhmaykoosib Inninuwug First Nation (KI/Big Trout Lake) |
| Roopa Rakshit | KORI-LU |
| Breann Brunton | Windigo First Nations Council |
| Tom Semple | Kasabonika Lake First Nation |
| Mary Barkman | Sachigo Lake First Nation |
| Georgina Winter | Wapekeka |
| Helen Winter | Wapekeka |
| Donna Brunton | Shibogama First Nation Council |
| Lenore Robson | Ontario Energy Board ($24^{th}$ only) (OEB) |
| Mary Anne Aldred | Ontario Energy Board ($24^{th}$ only) (OEB) |
| Richard Habinski | Windigo First Nation Council |
| Franz Seibel | Keewaytinook Okimakanak (KO/Northern Chiefs) |
| Richard Chukra | Independent First Nations Alliance (IFNA) |

# Minutes of the Workshop

## <u>Day One</u>

The meeting started at 9:00 am with introductions around the table.

## Presentation #1:  Watay/Opiikapawin Project

Richard Habinski (Opiikapawin Services LP) presented the Watay/Opiikapawin project timelines and key accomplishments to date.

<u>Summary</u>:
Huge accomplishment: Watay was designated as a transmitter by the province of Ontario. Transmission line planned in two phases, Pickle Lake to east of Wabagoon and the connection of seventeen communities. The cost is estimated at $1.35B, 770 jobs will be created, 260 in NW Ontario. Watay successfully applied for its transmission licence and through Opiikapawin and the Environmental Assessment has started its planned community engagement on the project. The good news is that the two phases of work are getting closer together. The Leave to Construct efforts started in 2017, and will be filed for Phase 1 (Pickle) in 2018, and for Phase 2, (the community connection) starting in 2019.  By 2023, communities will start being connected.

Many milestones have been met:
- Phase 1 EA now frozen
- Ministry of Environment and Climate Change are reviewing
- Leave to construct filed fall 2017

The project is progressing well.

## Presentation #2:  Hydro One Remote Communities' Operations

Kraemer Coulter (Remotes) gave an overview of Hydro One Remote Communities' operations as an LDC.

Questions regarding Remotes overview**:**

**Question:** **Does INAC offer fuel subsidies to IPAs?**
Answer (INAC): INAC does not have a guaranteed program to subsidize fuel, but assesses need and available resources year to year. INAC does offer operational support to IPAs. If IPAs have issues, they should contact INAC.

**Question:** **Is there support from INAC?**
Answer (INAC): Communities can ask, and if we can find funding, then we help. Funding is not always there.

**Question:** **Shares in Hydro One are being sold. Will this affect rates?**
Answer (Remotes): Rates are set by the OEB. The sale of shares will not affect the way rates are set.

**Question:** **Can IPAs continue to operate and become LDCs?**
Answer (INAC): In Ontario, there are fewer LDCs than there used to be. INAC will work with IPAs to reduce the risk of operating in the short term.

**Question:** **Who pays the A rate?**
Answer (Remotes): Government funded accounts like the Band Office and School.

**Question:** **Why will Standard A rates apply when communities are connected to the grid? Will rates go up at grid connection?**
Answer (Remotes): We do increase our rates by inflation every year. Hydro One Remotes' rates are not set to cost. When we applied for our last cost of service, we asked to keep our existing rates for non-Standard A customers and requested a grid connected Std A rate for our Government funded customers. We can't guarantee that the overall rate structure will stay the same forever, but the rates are based on the information we have now and the rules in place now.

**Question:** **How will the sell-off of Hydro One affect rates and customers?**
Answer (Remotes): Our conditions of service have not changed. Rates will continue to be approved by the OEB under the rules that are in place, regardless of ownership.

**Question:** **Will privatization affect rates?**
Answer (Remotes): We are set up with no return on equity and do not expect that to change. We do not foresee ownership affecting rates.
Answer (INAC): INAC's role is to work with communities to develop solutions to meet their needs. It is up to communities to identify their needs and initiate

early discussions with INAC (and Remotes if relevant). INAC integrates the needs developed locally into the INAC regional process for priority setting.

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| **Question:** | **What is happening with connection restrictions? Will investments go forward now that the grid is planned?** |
| Answer (Remotes): | We gave INAC a 15 year snapshot of requirements. It doesn't make sense to build an $80 million station if the grid is coming, so we are being creative. Our new process shortens the window for new connections, but it is a delicate balance. We have to be safe and reliable. If Watay doesn't happen or happens late, we may be doing a bit of a dance to keep these priorities balanced. We are fortunate to have INAC support and more alignment of our needs.<br>We are working more closely with INAC, trying to innovate and be flexible. I will talk about our new process late this afternoon, but as an example we are working with KI and Wapekeka to build a tie line that will allow the two stations to operate together and that will increase capacity as a result. If the communities connect to the grid, the tie line will already be there. Another example of our approach is that part of our traditional requirements for an upgrade is to build new fuel storage capacity. We are looking at installing solar panels on non-Standard A accounts to off-set diesel use instead. |
| **Question:** | **INAC is working with Hydro. What about First Nation needs?** |
| Answer (Remotes): | This process includes First Nations, who identify needs and who make the decisions on the project for which funding is requested. |
| **Question:** | **How will Watay work with renewable energy? We have been working with Solar Power Network by making an application for a solar grid in Bearskin. We are also looking at other options. Our goal is to develop a run of the river site along the Severn. If Watay does not happen, is there any potential to make a micro grid for Muskrat Dam and Sachigo?** |
| Answer (Remotes): | Under our Reindeer program, we would pay for electricity that reduces our use of diesel fuel, based on the price of diesel. |
| **Question:** | **If Watay goes through, the line will be single circuit and there will be blackouts. Who is responsible for the backup plan?** |
| Answer (Remotes): | The OPA/IESO did a diesel backup study. There is no decision yet on how backup power will be provided. It will likely be on a community by community basis. Each First Nation will need to decide. |

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| **Question:** | **Why not build the line double circuit because it would double the cost of the project? Who is responsible? INAC? Hydro One?** |
| Answer (Remotes): | We are on the sidelines in terms of the Watay design. Our job is to deliver power to our customers. It may not make sense to double up the line because there are a small number of customers with long lines over long distances. |
| **Question:** | **Fiber Optic within the communities is not at full capacity. People are not hooked up.** |
| Answer (Remotes): | The Fiber connection varies from community to community. Some stop at the nursing station, some before town. |
| **Question:** | **Fibre Optic is not very reliable.** |
| Answer (Remotes): | Hydro One is looking at a dedicated line for its operations. For our project in KI-Wapekeka, we are looking at a dedicated line. |
| **Question:** | **Why not use local lines? It is easier to go through a local company. For Wapekeka and KI, you should go through the communities.** |
| Answer (Remotes): | We are rolling out satellite and fibre and are comparing the reliability and costs. Our approach is to go community by community and compare results as we go. |
| **Question:** | **How will you know if there is an outage? Someone needs to call the First Nation so you will know.** |
| Answer (Remotes): | To some extent, our operators are our ears on the ground. Real time monitoring will let us see the detail of what is wrong. |
| **Question:** | **Is this a waste of money? Will that be reflected in community bills?** |
| Answer (Remotes): | Customers need service, and we believe this technology will help us prevent catastrophic failure. |
| **Question:** | **I have been on council for about a month. You say that you have been 14001 registered since 2002. What I've seen is Dyke Water spilling into the roadway. Are they causing problems? There are air emissions in the summer.** |
| Answer (Remotes): | In terms of the Dyke water, the water is clean. It has been sampled and filtered. We test it regularly. |
| **Question:** | **Do you keep emission levels for each station? Do you have targets?** |

Answer (Remotes): To get MOECC permission to operate the plants, they do a technical review of the design. MOECC evaluates the model. We use maintenance practices to keep emissions within guidelines.

**Question: There was black smoke coming from our plant.**

Answer (Remotes): We changed the controls of the plant and adjusted to reduce the black smoke. If this is ongoing, we can potentially install taller stacks.

**Question: We can smell the plant in the summer. Community members hanging clothes on lines can't, because it smells like diesel. The plant is noisy. In other communities the plants are near the airport. Sometimes we see black smoke coming from the plant. What causes that?**

Answer (Remotes): You should not smell the plant. If there is smoke or a smell coming out something is wrong. It is usually temporary on start up or shut down, if it is continuous there is an issue and you should give us a call. The plant located downtown was not our choice. We always request the plants to be located at the airport.

**Question: Do you monitor when connection restrictions come close? We are concerned about our community's ability to grow.**

Answer (Remotes): Government spending constraints affected our ability to connect. Now we have a way to do interim incremental capacity increases.

**Question: We only see Hydro people when they come to the community to connect or disconnect. We would like more community presentations. Young people don't know who Hydro One is.**

Answer (Remotes): We meet with Chief and Council regularly and do Hazard Hamlet/Safety presentations in schools to help young people understand public safety, but we will consider community meetings.

**Question: I want to know about the location of distribution poles in the communities. We recently had some problems with our water in the community. We realized the lineman just put the distribution pole where it's convenient, near the waterline. We had a water crisis and had to dig up the water line. The pole was too close to the waterway and could not dig up the line there.**

Answer (Remotes): Normally utility corridors are shared among water utilities, electric utilities and any other utilities. It tends to be cheaper and helps people determine where to build roads, houses etc. There are clearances that are defined by standards. We will respond to this kind of emergency if you call our emergency number. Someone will come to the community and help locate lines.

**Question:** **How did you resolve the problem?**

Answer (Remotes): We closed up the line further down.

**Question:** **The breaker flipped in the community. Can operators fix that?**

Answer (Remotes): Yes. Operators are trained to respond to emergencies in the plant and on the distribution system. They can refuse transformers, respond to emergencies like house fires and make safe.

**Question:** **When something happens, like a fire, the whole community goes out of power for a while. Why?**

Answer (Remotes): Most operators are not trained to perform live line work. We ask them to shut down the station for a short time to respond some distribution emergencies so they can perform the work safely.

**Question:** **Do operators need assistants?**

Answer (Remotes): In most communities we have backup operators who do some of the work and who work when the operator is sick or on vacation.

**Question:** **The grid is coming. Remotes knows this. The IPAs have to upgrade their systems. Who will foot the bills for this work?**

Answer (Remotes): We have agreed to work with the Tribal Councils and IPAs to perform asset assessments with the ESA to ensure that the assets meet provincial standards for public safety. The federal government (INAC) and Opiikapawin have worked together to fund these assessments and we expect they will fund the work to bring the assets up to standards.

Answer (OSLP): Several IPAs met in Sioux Lookout recently. The IPAs are looking to hear about the relationship with Hydro One. At that meeting, Deer Lake gave a presentation. They said that the relationship is two way. You get what you put into it. The IPAs are also looking to hear from you on the relationship you have with Hydro One.

**Question:** **There is work going on in our community. People are staying at the Hydro house and you rented another house. When you aren't there, you lock the doors. Why is the house only for Hydro One?**

Answer (Remotes): We have a lot of people and not enough beds so had to rent additional accommodation in the community. We rented it including weekends because we have people working seven days a week.

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| **Question:** | **What about jobs when the grid comes? How will they be shared among the communities?** |
| Answer (OSLP): | All the communities want jobs. We are working with Power Tel who will be doing the construction. Some jobs will be local some regional. |

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| **Question:** | **When does the work start?** |
| Answer (OSLP): | 2018. We have put together a training program on various work items that we expect to move forward with in 2017. We do not have information to share as yet on the timing of jobs. |

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| **Question:** | **What about the remediation in our community? There is monitoring by the generation station. What is going on there?** |
| Answer (Remotes): | We cannot remediate under the plant, but we monitor to see if the contamination is moving and to ensure it doesn't get into the water system. |

## Presentation #3: Customer Priorities

Una O'Reilly (Remotes) started her presentation with a priority setting exercise. Each First Nations representative was given six (6) $10 bills and was asked to place them on flip charts. The categories and "spending" were as follows:

| | |
|---|---|
| Community Relations: | 18 |
| Affordable: | 17 |
| Customer Service: | 17 |
| Renewable Energy: | 18 |
| Safety: | 11 |
| Reliability: | 14 |
| Environmental Protection: | 26 |

| | |
|---|---|
| **Question (Remotes):** | **Environmental Protection got the most votes, can someone tell me why they supported this as our first priority for investments?** |
| Community: | My grandfather told me to take care of the land. It's my religion to take care of the land. |

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| **Question (Remotes)**: | **What about renewable energy? Can someone talk about why that is a priority?** |

Community: Climate change is real makes sense to get our electricity and other needs from the earth.

**Question (Remotes)**: **And for Community Relations?**

Community: Hydro One needs to understand what customers want and their reality. Electricity is not affordable. People can't afford it.

Community: Customer Relations and Customer Service are Hydro One's weaknesses. Hydro One is strong technically, but its management of its customer base is week. For example, in the collections process, you wait for people to pay and then the burden shifts to the Chief and Council or to Ontario Works to get it (balances owing) covered. You act like an absentee landlord. You aren't in the community. You need to work in partnership with the community.

Community: On Community Relations, people want to pay their bills but are on the way to the band office and it is too late, people have climbed up the pole and cut them off.

**Remotes Discussion Point: Every month, customers get a bill telling them if their payments are late. When we plan our collection trips we send each customer and the chief and council letters repeated notices letting them know when we will be in the community, and that their accounts may be cut off if they do not call our office to pay or set up a payment plan they will remain on the disconnection list. We work with customers to avoid disconnection. The lesson here is don't wait till the last minute.**

Community: When they disconnect, they just put the meter off then back on.

Community: They just come up when they disconnect.

**Question (Remotes): They should come up and explain what they are doing before they disconnect?**

Community: Is there a possibility for customer education?

Community: Some of the families either choose to put food on the table or pay their bills. That is what is going on in my reserve.

## Presentation #4: OEB Regulation and Programs

Una O'Reilly (Remotes) delivered a presentation designed to determine the knowledge level of participants of the LEAP and OESP programs.

**Question (Remotes): Who administers LEAP and OESP?**
Answer: Ontario Native Welfare Administrators Association. You can reach them by calling their phone number, you can contact the welfare office on reserve or you can go on-line to apply for OESP.

**Question: What is the difference between OESP and LEAP?**
Answer (Remotes): Both programs use the same matrix to determine eligibility. For OESP, you apply and you get a monthly bill credit—your bill is reduced by the amount you qualify for each month. LEAP is a grant that you can get in an emergency. If you do fall behind and could face disconnection, you call ONWAA and they will see if you qualify for emergency help. You can get up to $600 to help you with your outstanding balance.

**Question: Is there a difference if the community is full service or Ontario works?**
Answer (Remotes): No, eligibility is based on household income. You can call ONWAA no matter which social assistance program (federal or provincial/federal shared) is in your community.

**Question: The winter months are the most difficult time. You come in January and disconnect.**
Answer (Remotes): We start sending notices in January, but do not disconnect until late April or May. Call our office early and make a payment plan. Apply for LEAP and OESP. These programs are there to help, but you need to apply.

**Question: How long does it take to apply?**
Answer (Remotes): LEAP approvals happen within 10 days of calling. OESP takes a couple of months.

## Presentation #5: Rates and Billing

Una O'Reilly delivered a presentation on Rates. Here are the questions and answers.

**Question: Why is there a Standard A rate on grid?**
Answer (Remotes): In our last cost of service we proposed grid connected rates based on our existing rates. Currently our rates are not cost based, but are set under a Regulation. Rates are normally based on the actual cost of service. The cost to serve the far north is high, and most customers are economically disadvantaged. The provincial government has recognized this, so rates

are not set to costs. For residential and commercial customers in the north, the rates are actually a bit lower than rates for grid connected customers. The Standard A rates are charged to government customers to share the cost of service between governments and rate payers. The grid connected rates we had approved are much lower than our current standard A rates and are about the same as those charged in the FNEI communities—about 30 cents per kWh—and not much higher than a grid connected customer—about 23 cents per kWh.

**Question:** **How did you get to 30 cents per kWh?**
Answer (Remotes): We took out all of the costs related to diesel generation and added in the cost of power.

**Question:** **If you don't have an exemption and your status number is not showing on the bill does that mean you are paying taxes?**
Answer (Remotes): Yes. If you don't see the status number on the bill, you should call our office. You need to send them a copy of your status card to be exempt from HST.

## Presentation #6: Customer Service (Connections, Collections, Safety and Environment

Kevin Mann (Remotes) delivered a presentation and led a discussion on Connecting to the Distribution System. The following are the questions and answers regarding this presentation.

**Question:** **Why do we have to pay up front?**
Answer (Remotes): We get payment up front to reduce our collection activities, to help us schedule the work, to be sure that the connections are going forward.

**Question:** **Why does it take so long?**
Answer (Remotes): We do our best to connect everyone as soon as our conditions are met. We have limited staff and operate on a first come first serve basis when all requirements are met. The problem is, everyone wants their connections in the late fall.

**Question:** **Some homeowners have poor connections in their homes. Some have circuits that haven't worked for the last two years. Why are these not found by the ESA?**

Answer (Remotes): The ESA checks grounding, spot checks other items. They do not look at the wiring in the entire house. You need to hire qualified electricians.

**Question:** **Does anyone in your office who answers the phone speak the language? It's nice to have someone who speaks the language. For connections, you should take 50% payment instead of 100% December is a hard month, there is a fiscal crunch in December.**

**Question:** **We are building a building in our community. Who do we talk to? If you have to relocate a line, is it expensive?**

Answer (Remotes): Call our office and talk to the customer service staff. If you have to relocate a line to build your building, it may not be the best location.

**Question:** **At one time the band purchased a big generation set. We then had to purchase our own 725 kW unit when the big one failed. Why isn't there a discount for this? Maybe it will just work for a while before the grid comes. There should be a discount of dollars the FN has spent on gensets.**

Answer (Remotes): There is no rebate to customers for this. At the time this was first put in place, the FN decided to build and own a generator rather than to do an official upgrade. We have an agreement to operate and maintain this engine and we buy the fuel. We do not give a discount to the FN because it is harder for us than a normal station would be.

**Question** **Two questions: For a payment plan, is automatic deduction available? We had a power outage yesterday. The meter was still running.**

Answer (Remotes): Yes we can make payment plans that are automatic. When there is a power outage you should call the office.

**Question:** **In terms of collections, someone who is paying every month is still on the disconnection list, while someone else owing a lot was not disconnected. Can a person who was paying get back on the list?**

Answer (Remotes): We don't disconnect people who pay. If you default on a payment plan, you can be disconnected.

**Question:** **Isn't it expensive to disconnect just one to three people?**

Answer Remotes): Our goal with collections is to cancel the trip, to have everyone pay so we don't need to make the trip. We do have people go to a number of communities in a single flight to reduce costs.

**Question:** **Why does the Chief and Council need to know someone's bills?**

Answer (Remotes): Most Councils want to know if someone is going to be disconnected so they can help if needed.

**Question: Safety, when live wires are down in emergency the police need to run around to find the operator.**

Answer (Remotes): Call our office. Someone will answer the phone 24 hours a day, seven days a week and we will track down the operator or back-up operator to make the wires safe. If the incident involves a car or heavy equipment, stay in the car until someone comes. The emergency handbook was delivered. Our linemen knocked on doors and gave these to some emergency responders. Stay 3 meters (10 feet) away from the downed wires.

**Comment (**Remotes)**: Share this handbook with Tribal Councils to ensure it gets to emergency responders.**

**Question: Joint use agreements, do you have them in all communities? Do you charge fees to attach to poles?**

Answer (Remotes): We have agreements in the majority of communities. There is a handful where we don't. We do not charge fees to attach to poles. We have an agreement to protect public and employee safety. Our agreements provide for required clearances and capital sharing if the pole needs to be replaced with a taller pole.

**Question: You have all these programs. If we have ideas would you consider implementing them?**

Answer (Remotes): Yes.

**Question: Would you implement a streetlight program to repair or replace streetlights?**

Answer (Remotes): We have a program to help First Nations pay to replace streetlights if they are energy efficient lights.

# Day 2, November 24, 2017

## Presentation #7: First Nation Energy Rate Options

Lenore Robson (OEB), gave a presentation on the Minister's request to develop options for a First Nation Energy Rate. Comments/Questions:

**Question:** **What about the future? What happens when we are connected?**
Answer (OEB): We are looking at something across the province.

**Comment:** **Is there flexibility in what the OEB can recommend? The province is not one size fits all.**

**Comment:** **The cost of living is much higher in the remote north than in southern First Nations like Lac Seul. Food costs are very high. Income levels are lower. Most people rely on seasonal work. The communities are also facing social problems, difficulty with drugs and opiates. Our communities face poverty.**

**Comment:** **Up to 70% of people in our communities rely on welfare. The cost of living is very high.**

**Question:** **Will privatization affect Hydro One's rates?**
Answer (Remotes): There are no plans to change the way Hydro One is operated (i.e., return on equity). Rates are regulated by the OEB that will continue.

**Comment:** **The other major difference between the remote north and the south is that there are fewer alternatives to electricity. Alternatives to electricity are costly. $1.90 per litre of fuel for heating for those people who have medical needs and can't cut wood or use wood stoves.**

**Comment:** **The federal government has cut back on costs. It is a common problem in reserves. The federal government needs to give more money to reserves. Maybe your report should go to the Prime Minister.**

**Comment:** **The government should look at water power in the north.**

**Comment:** **The program should apply to Standard A rates.**

**Comment:** **The program should not be application based.**

## Presentation #6: Customer Service (continued)

Kevin Mann (Remotes) delivered a presentation and led a discussion on Connecting to the Grid on Day One. The following is an additional questions and answers regarding this presentation.

**Question:** **The REINDEER program is based on the avoided cost of fuel. Can this also reduce costs for residential customers?**
Answer: Yes, but generally solar is expensive to install in the north, so most communities decide to put solar on Standard A services to get the best bang for their buck.

## Presentation #7: Reliability and Generation Asset Investments

Oli Laskujarvi (Remotes) delivered a presentation on reliability and asset investments. There were no questions or comments.

## Presentation #8: Generation Capital Upgrade Process

Ralph Falcioni (Remotes) led a presentation on recent changes to the capital upgrade process. There were no questions or comments.

## BREAKOUT SESSIONS

The rest of the meeting was devoted to breakout group discussions and recommendations for the First Nation energy rate and service improvements in Remotes.

Comments from the three breakout groups from the workshop can be found in Appendix "A". The remote First Nation communities cannot be rolled into a "one solution fits all" category. The realities of living in remote First Nation communities require different solutions than non-remote communities. The issues need to be dealt with separately. Access to goods and services as well as jobs is negatively affecting remote First Nation community members' ability to survive on a day to day basis.

The information on the "flip chart" summary is from the discussions with the participants after the OEB presentation. There is information referencing the OEB presentation as well as the information provided by Hydro One Remotes. This information was gathered in an informal group setting and has not been altered. It indicates that there are still a lot of question and concerns from the group and that there needs to be a lot more follow-up discussion on the topics. Some individuals had very different perspectives on the problems and this alone requires more follow-up and discussions. We are planning on having a follow-up meeting in the New Year with our Independent Power Authority and Hydro One Communities

## Breakout Session Group Flip Chart Notes

The following is the comments and feedback from community members at November 23 and 24, 2016 workshop after the OEB presentation. Also included are comments regarding Remotes service.

**Group 1 Feedback:**

- **Drop Standard A rates for remotes:** The current Standard A rate is 97 Cents/kWh for all the Government funded buildings and with grid connection it will drop to 29 Cents/kWh. It was suggested to consider implementing the 29 Cents/kWh now for a smooth transition to grid connections. OEB could help subsidize that.
- **Drop delivery charges:** Delivery charge was for the grid connected communities in the south that they wanted gone. To consider getting rid of monthly charge on bills for the northern First Nations.
- **Subsidies:** To be cautious on the subsidies during discussions with INAC and to ensure that they need to maintain the current Standard A rate subsidy until the grid connection. Funding cannot be reduced or stalled/when they see cost-savings. (When formulas are calculated for operations and maintenance, the Standard A rates are included and built into the subsidy electric component)
- **Other subsidies:** Construction costs for connections (poles etc.) are much higher in the North than in the South.
- **Breakdown of the bundle rate:** The true cost of the power for North is to be provided towards customer education. The breakdown will facilitate better understanding of revenue sources, and payments made on specific allocations by home owners. Even though community members pay a subsidized cost, the breakdown could serve the purpose of an educational tool for RRRP and residential rate payers.
- **Customer relations and Customer service**: To enhance, the group suggested to tie into processes and structures through local RRRP workers who are closer to the communities and delivers energy programs. To initiate a customer education process on rates, bills etc., as part of customer education-a community-based approach. The conservation program could also be brought back as a behavioral modification on using less power, on using technologies that reduces consumption, bills. (H1RC have an application-based…appliance program)
- H1RC in partnership with the community could engage with the rate payers on conservation, consumer education programs besides the bill collections. **More presence:** Remotes and OEB are asked to have more presence in the community.

- **Late payment charge**: 19.5% on an annual basis is too high and the time frame that kicks in is too short with 20 days. To consider with 60 days' time frame and to be tied to borrowing rates/user rate fees and not market-based rates.
- **Application based programs:** Special consideration is to be made for seniors and elders who find it difficult to navigate through the application process. Try to build/tie into some of the activities showed in the bill and maybe make them "automatic" rather than applying for them.
- **Include an "adder" to off-grid renewable projects:** REINDER programs are not enough, there need to be an "adder" to the REINDEER rate, as an incentive. The "adder" should consider the impact of reduction of the standard A rate. The renewable projects could be made more attractive to find capital/funding for the remotes.

**Community-specific concerns:**

- KIFN: Senior complexes-individual apartments owned by seniors get Hydro bills but there is no funding for common areas.
- Bearskin: 20$% rebate across the board, on everybody's' bills -suggested directing the savings towards employment, childcare, education, lands and resources, restaurant etc.

**<u>Group 2 Feedback:</u>**

- **Electricity rate:** Hydro bill are too high. To consider seasonal rates as lot more electricity is used in the winter. Or, people who don't have woodstoves have higher costs, especially for the elders and seniors. There are cases with high bills and no jobs. To consider percentage reduction of energy bills.
- **Subsidies:** All customers are different. Some have trucked water, and require lots of electricity to run pumps, so, it is not one size fits all when considering subsidies.
  **Power, food, health, Nexus:** Anecdotal references were made to situations when options is not food versus power with both being essential necessities. Junk food is cheaper which leads to health and medical treatment issues that are cost intensive. Profile of a different family sizes can be acquired from community economic development offices to iron out fairness in payments. Single mothers, grandparents caring for grandchildren, mentally-challenged, and disabled patients who are unable/or shy away from the welfare application process, become dependents on regular families stretching family budgets. There are no resources to bridge the application process.
- **Incentives**: Incentives for reduced energy use.
- **North versus South unfounded perspectives:** Decision-makers from the South have to visit the northern communities to see first-hand, ground realities. The communities in the north have to deal with a lot more situations that the south doesn't face. Also, "Thunder Bay is not north or reflective of the TRUE NORTH". Also, get an understanding of family structures and community way of life.

- **Energy Star Program**: To be made available to everyone and not just for low-income group people. The H1RC program swaps old appliances for Energy Star appliances.

**Feedback on the Remotes processes:**

- **Community relations**-To understand community' expectation on building relations-"H1RC version is different from ours". Mostly council members attend meetings in Thunder Bay and sometimes the information flow is restricted or stalls at that level. Suggestion was made to engage with the communities more through community meetings organized for EVERYONE to attend, open houses, FB, radio etc. Also, forward materials that are easily understood by the community. Sending program promotional/marketing pamphlets with bills doesn't always work.
  People who implement programs like OESP and LEAP need to go to communities, help them with the application process.
- **Housing:** Lack of housing leads to overcrowding that lead to high electricity bills (e.g.: North Caribou. Also, with large families, it is very easy to go over the first 1000kwh threshold. To consider up to 2000 kWh before increase.
- **Renewable projects:** Community is interested to invest**,** own and run more renewable options.
- **Standard A** rate on band council building and assets needs to be lower. Shouldn't have to wait for grid connection to get lower standard "A" rate. Don't want rates to change or access to RRRP to go away when grid comes in. Need more than just the $20 service charge off and not make it comparable to the delivery charges of the south.
- **Joint process**: Consult with INAC for cost savings on when the grid comes in. And ensuring that any subsidies that come from OEB does not reflect on a reduced cost saving options from INAC.
- **Subsidies**: Should not be something we have to apply for.
- **Additional concerns:**
  - Lots of power surges with diesel generation or power goes out for a few seconds. Thus, outages should result in lower bills and should be reflected on the bills.
  - Sometimes when they come to communities to do the disconnections, they won't take any cash.
  - Disconnect charges add an extra burden and are varying from 65$-165$ that ensues a long wait to be reconnected once the bill is paid.

**<u>Group 3 Feedback:</u>**

- **Standard A rate:** There are two rates-one for the First Nations and one for the Municipal. So, the community deals with the individual bills and Municipal/Band type accounts. Rates are high that the Band offices have to sometimes pay from other programs. It was suggested that the respective community band offices need to be made aware that with the grid connections, there is a possibility of the reduced/stalling of the INAC funding and subsequent subsidies. This needs clear understanding amongst all of us and we should be on the same page.

- **Understanding realities:** Both, the communities and H1RC want to be treated fairly and so, to approach the system through a holistic lens. There are realities on both sides-to acknowledge and respect. Adding or subtracting services without realizing the ground realities leads to misunderstanding and lack of expectations.
- **Time of Use rates:** Do not want time of use rates as there are unemployed people and energy consumptions to consider. Using the time of use rate will only hurt us.
- **Cost of living:** To take into account the cost of living and all costs including freight as they are significantly higher. Everything costs double in remote Northern Stores even with a subsidized rate.

  Need to help seniors and Elders who cannot keep up with the costs of living. Reference was made of the 700+ OESP applications that are stuck in the systems process. This is not acceptable when community members rely on these programs. OEB could address the issue with the Ministry of Finance.

  Also single parents, some are too young to apply and get into the system. Grandparents are playing the roles of the parents and have extended responsibilities.

  Welfare is $400/month/person. How much can it be stretched to in a typical size family?

- Need to keep **"entrench"** RRRP and Standard A subsidies on a long-term basis irrespective of change in Governments. To ask the Province to approach INAC.
  Rates cannot go up (increase) with connection to the Provincial grid. If that happens then there is no value in being connected to grid. We cannot burden communities with additional payments-a principal used for guidance with grid connecting.
- **Customer Services:** Place someone in our community that can help with applications/Forms. Also, need help within the communities with arrear management and not just a 1-800 number. To include management of bills, when trying to decide how to pay all bills-food, fuel or electricity.
  Reliability is a problem. Need someone in the community to keep the lights on. To explore solutions, H1RC need to visit the communities and talk to community members. Or the community can set a program and appoint someone in the community in partnership with H1RC. The group stressed on **education and communication**. Reference was made of initiating financial management skills.
  The group echoed that we are "remote" and have unique set of challenges. All FNs cannot be treated the same. Comparisons between the North and South should not be made. Reference was made with Land-Fill sites as an example.
- **Renewable Energy:** Walk hand in hand in renewable projects.
- **Watay Power:** To have discussions on bills and payments post grid connection. It is important to prepare the community.

- **Conservation:** Stressed on H1RC conservation programs, appliances and light bulb replacement etc.
- Payments: Payments upfront
- **Back up generation**: A must for any catastrophe for basic services. No compromise on that. To consider portable units by H1RC. It is not only a back-up system, there are financial implications too.
- Quick response time, especially in the winter-someone on standby 24/7. Faster service.

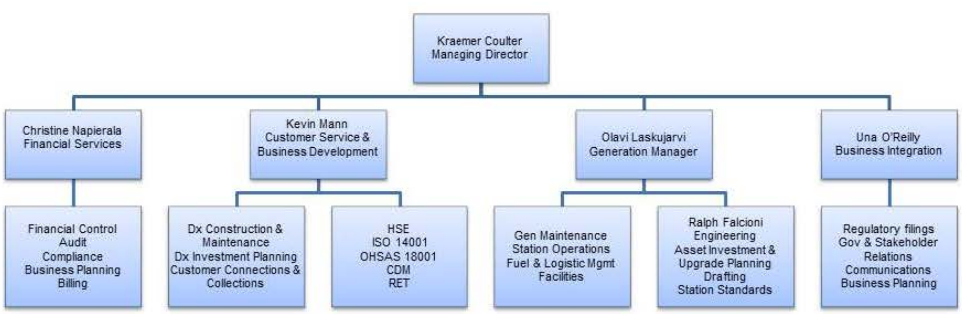
# PRESENTATION MATERIAL

The following are the presentations delivered during the workshop.

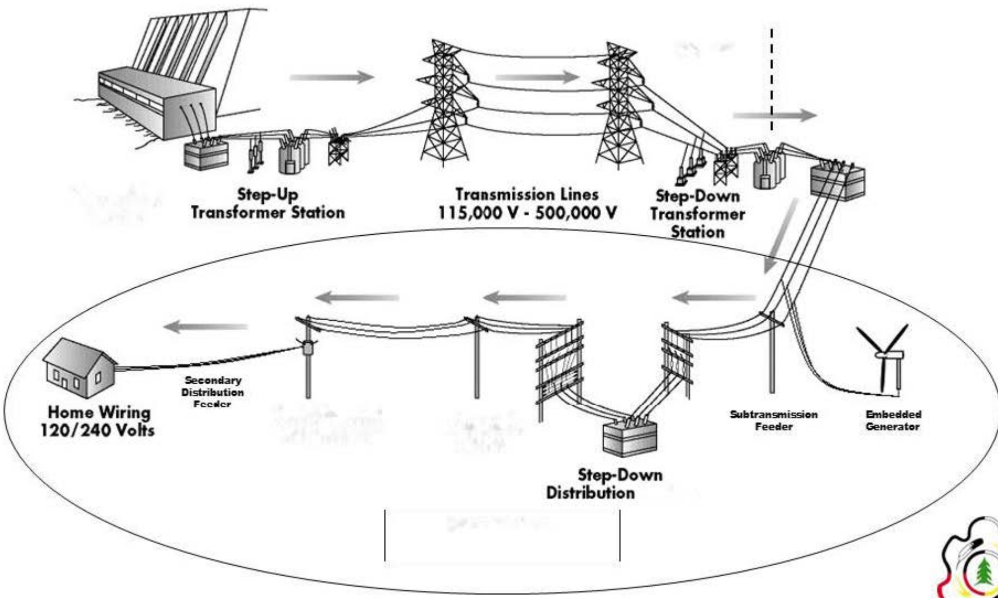
## Agenda:

- Overview of H1RC
  - Who are we?
  - What do we provide?
  - What are our rates?
  - What do our bills look like?
  - How do we collect?
  - How do stations get upgraded?
  - How do you get connected?
  - How do we plan investments?
  - How will transmission change things?
  - What makes us different than an IPA?
- Q & A

## Our Organization



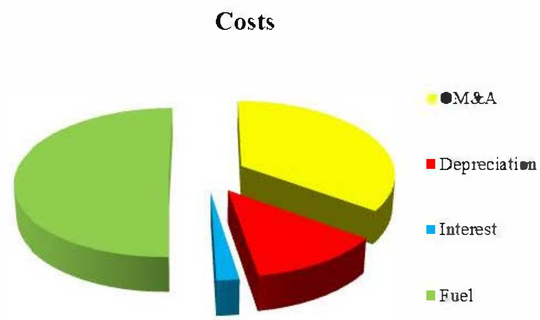
## Typical




## Our Costs

- We all know that the costs to serve the remote north is high
- Fuel is our largest single cost: 17M Litres
- Our business is operated to break-even … We do not make a profit!

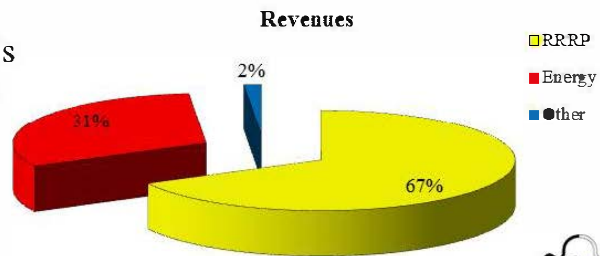
- Any $ differences between our revenues and costs are recorded for future consideration by the OEB
- Costs must be prudent to be recovered



## Our Revenues

- Rates for residential and business customers are set below the cost of service and actually the cheapest in Ontario – even grid connected!
- Standard A (Government) customers pay rates slightly above cost
- Together, customer rates provide about 31% of our revenues
- The shortfall is made up through the provinces Rural or Remote Rate Protection Program (RRRP)

- Approval of this funding is determined through a rate hearing at the OEB
- OEB staff and other ratepayers challenge our budget and revenue plans




## H1RC – Licenced Full Service Provider

Services:

- Manage all aspects of the Dx and Gen systems including system planning, design, construction, joint use, mtce scheduling and execution
- Provide a full complement of skilled generation and distribution staff - Linemen, Technicians, Mechanical, Electrical, Civil maintainers, P&C Techs, Engineering and Operations coordination all centred in Thunder Bay.
- Provide training and support for Operators and meter readers
- Internet monitoring of all systems at our Thunder Bay facility
  … currently leveraging new fibre network to have 24/7 real time monitoring

## H1RC – Full Service Provider

Services:

- Toll free Emergency Number with 24/7 coverage for generation or distribution issues … any customer or the plant Operators just need to pick up the phone for service and support
- Provide specialized equipment like RBDs, line mtce and gen tools
- Perform load balancing and fuse coordination to ensure the system works as designed
- Monitor community load and work with the First Nation and INAC on capacity concerns and upgrade options
- Provide mechanism for the purchase of renewable energy

## Community Benefits

Provide all aspects of Fuel Management

- Tank farms and fuel systems meet all code requirements
- Fuel systems are maintained, tanks are cleaned, and levels are monitored (locally and remotely) to ensure there are no leaks
- We are registered to ISO 14001 and take environmental protection very seriously and hold contractors and ourselves to a high standard
- We specify and monitor fuel for quality, order, arrange for transportation, and pay for all fuel
  - significant reduction in burden to the community compared to an IPA!
    … not only on management effort but on the financial side!

## Community Benefits

### Full Logistics Management

- Distribution and Generation equipment and material is ordered and delivered as needed
  - No need to worry about hiring a contractor, ordering poles, transformers, wire, to maintain the distribution system or connect houses
  - No need to worry about hiring a contractor to maintain the generation station or ordering oil, filters, batteries, or other supplies for the station

    … the Operator deals directly with us, we pay for his time and materials
  - No need to worry about what to do with the waste oil

    … it is removed from the community!

    … not the case in IPA communities.

## Community Benefits

### Partnerships

- Mutually beneficial agreements to purchase fuel
- Shoulderblade Falls partnership: agreement to own and operate hydro electric plant and share benefits

### Customer and Community Support

- Customer Advisory Board
- Public Safety information and presentations
- Conservation programs and funding
- Power Play and Community Sponsorships
- Student Scholarships and college program support

## Community Benefits

### Lifetime Warranty

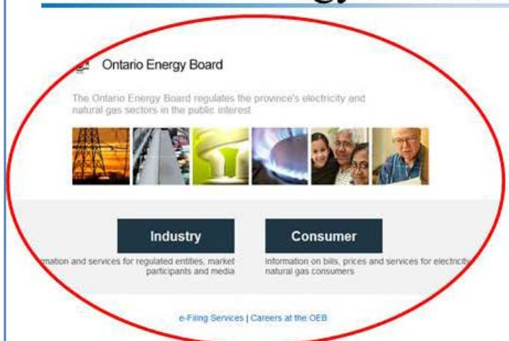
- On all like for like replacements!
  - All transformers, poles, wires, generators, engines, auxiliary systems, etc.
  - Plus provide many system upgrades at no cost so that we can provide the service and power quality that all of our customers deserve

### Safe Reliable Power

- 24/7 coverage for generation or distribution issues … only a phone call is needed and we look after the rest
- System generation **reliability** was **99.998%** in 2015

  … top 25% performance compared to our peers across Canada

## Ontario Energy Board




***Decides:***

which customers we serve

what prices we charge

sets our budget

***Sets standards and rules:***

Reliability

Customer Service

Payment rules

***Helps Customers***

Independent Agency

Resolves complaints

Creates programs

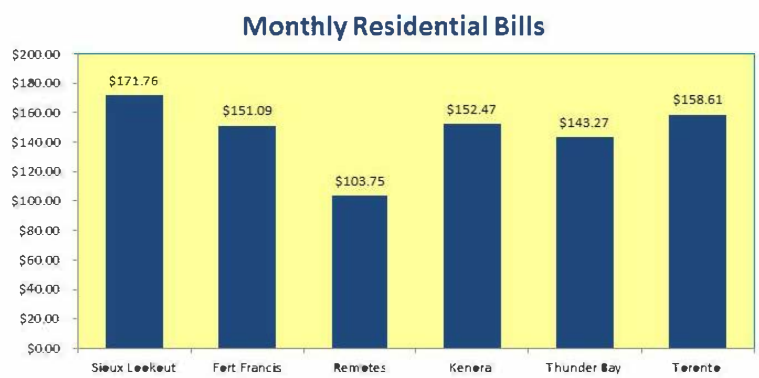
Ontario Electricity Support Program (OESP) and
Low Income Emergency Assistance Program (LEAP)

## Our Rates

| Residential | |
|---|---|
| Monthly Service Charge | $19.09 |
| Energy Charges (Cents/kWh) | |
| • First 1000 | 8.98 |
| • Next 1,500 | 11.98 |
| • All Additional | 18.06 |

| Standard A General Service Energy Charge (Cents/kWh) | |
|---|---|
| Off-Grid Diesel | 97.69 |
| On-Grid | 30.61 |

## Our Bills




All Bill amounts include HST, NOT charged to First Nations on Reserve.

- Our Residential and Commercial customer's bills are lower than rates in the rest of the province
- Government-funded off-grid (Std A) customers pay higher rates.

# What does our bill look like?

hydro one

Service address: MR.
MRS.
FORT SEVERN

Your account number: 29000
Tax exempt number: CSR

Billing date: March 23, 2016

Page 1 of 2

Customer service

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, Ontario
P7E 6G9

For billing and service inquiries, call
1-800-465-5085
Monday to Friday
8 a.m. - 4:30 p.m.
Eastern Time

For 24-hour power outages or emergency service, call
1-888-825-8707

## Here's what you owe

| | |
|---|---|
| Balance forward that is past due | $26.01 |
| Your new charges | $113.36 |
| Adjustments | $2.24 |
| **Total amount you owe** | **$141.61** |

The total amount you owe, as indicated on this bill, is due on the billing date. Your payment for this invoice is due on **April 11, 2016** (the Required Payment Date).

If payment is not received by April 11, 2016 (the Required Payment Date), a late payment charge of 1.5% compounded monthly (19.56% per year) will be calculated from the billing date and applied to your next bill.

This is a reminder that your bill has a past due balance. If this amount has been paid, please accept our thanks and pay only your new charges. If you are having trouble paying your bill, please call us.

# What does our bill look like?

| Compare the electricity you are using | Number of days | Average electricity you used per day (kWh) | Type of read |
|---|---|---|---|
| **Feb 16, 2016 - Mar 16, 2016** | **29** | **36** | **Actual** |
| Jan 15, 2016 - Feb 16, 2016 | 32 | 55 | Actual |
| Dec 15, 2015 - Jan 15, 2016 | 31 | 73 | Actual |
| Nov 17, 2015 - Dec 15, 2015 | 28 | 56 | Actual |
| Oct 19, 2015 - Nov 17, 2015 | 29 | 78 | Actual |
| Sep 17, 2015 - Oct 19, 2015 | 32 | 67 | Actual |
| **Feb 17, 2015 - Mar 18, 2016** | **29** | **33** | **Actual** |

hydro one

Please return this slip with your payment.

Your account number: 29000

Total amount you owe $141.61

Amount enclosed $

MR.
MRS.
GD
FORT SEVERN ON P0V 1W0

HYDRO ONE REMOTE
COMMUNITIES INC.
PO BOX 4102 STN A
TORONTO ON M5W 3L3

29000

## What does our bill look like?

Service address: MR.
MRS.

Your account number: 29000

Page 2 of 2

### How we calculated your charges

**Balance forward**

| | |
|---|---|
| Amount of your last bill | $372.48 |
| Amount we received on February 26, 2016 - thank you | $123.14 CR |
| Amount we received on March 14, 2016 - thank you | $100.19 CR |
| Amount we received on Ma ch 18, 2016 - thank you | $123.14 CR |
| **Balance fo wa d that is past due** | **$26.01** |

## What does our bill look like?

**Your new charges**

Your service type is Residential - Normal Density

**Electricity used this billing period**

| | |
|---|---|
| We read your meter on March 16, 2016 | 060296 |
| We read your meter on February 16, 2016 | - 059249 |
| Difference in meter readings | 001047 |
| Electricity you used in kilowatt-hours (1,047 x 1) = 1,047 kWh | |

| | |
|---|---|
| Electricity: 1,000 KWh @ 8.8000 ¢ | $88.00 |
| 47 KWh @ 11.7300 ¢ | $5.51 |
| Regulatory Charg s | $1.15 |
| Service charge | $18.70 |
| **Total of your electricity char es** | **$113.36** |

**Adjustments**

| | |
|---|---|
| Late payment charge ** | $2.24 |
| **Total adjustments** | **$2.24** |

** GST/HST exempt

## Connecting to our distribution system

- In Ontario, customers pay to connect to their distribution system.
- In our service territory, the Band normally requests and pays for new connections.
- We charge actual costs, but combine this work with other work in the community to keep costs down.
- We cannot proceed through the connection process without the right information and invoiced amounts.

*So how do I connect?*

## Connecting to our distribution system

- Planning for Service (Can you connect?)
- Request Service (What are you doing? What's being built? and where?)

  1-888-825-8707 or RemotesCustomerService.com
- Layout (Engineering Design) (Let's determine the plan)
- Account Set-up (Who is moving in or responsible?)
- Electrical Safety Authority (ESA) Inspection (Is it safe for the occupants and connection?)
- Construction & Connection (Let us built and connect it)
- Welcome….You're Connected (Yahoo!)

*When in doubt call 1-888-825-8707 (Customer Service)*

## Why does it cost so much to connect?

- Full cost recovery of labour, TWE, materials, flights, etc. (Logistics)
- The connection cost depends on the work required.
  - Install meter only $385 per service
  - Connection at Pole or Mast $885 per service
  - Connection at Mast and Pole $1,755 per service
  - Or more!

- Distribution systems are built to last and must comply with Ontario Regulation 22/04 Distribution Safety Standard
- We try our best to bundle work!

Remember that all material left in service comes with a lifetime warranty!

## Collections & Service

- The use of electricity and the payment for consumption is a business relationship between the utility and the customer
- It is not a political or personal….its just business relationship
- It is no different than going to a store where you are offered credit … if you don't pay you are not offered any more goods until you pay your bill

## Collections

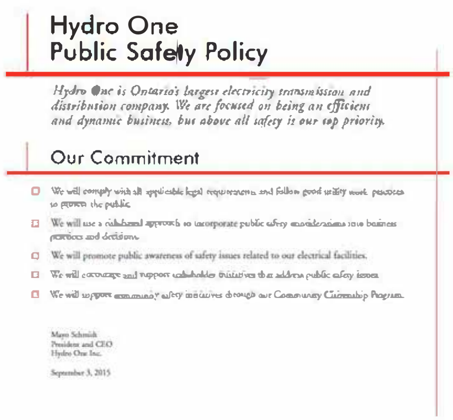
Collections Principles:

- Fair, consistent treatment of customers
- Communicate, communicate, communicate!


Process:

- Monthly bills sent to individual customers
- We do not disconnect customers in the winter
- Trips are planned months in advance.
- We communicate regularly with individual customers, FN Chief & Council and welfare offices.
- We encourage customers who fall behind to contact us and make payment arrangements or apply for LEAP or OESP
- Paying regularly is the best way to manage costs.
- Lowest rates in the Province

## Public Safety



Hydro One
Public Safety Policy

*Hydro One is Ontario's largest electricity transmission and distribution company. We are focused on being an efficient and dynamic business, but above all safety is our top priority.*

Our Commitment

- We will comply with all applicable legal requirements and follow good utility work practices to protect the public.
- We will use a risk-based approach to incorporate public safety considerations into business practices and decisions.
- We will promote public awareness of safety issues related to our electrical facilities.
- We will encourage and support stakeholder initiatives that address public safety issues.
- We will support community safety initiatives through our Community Citizenship Program.

Mayo Schmidt
President and CEO
Hydro One Inc.

September 3, 2015

We regularly communicate our commitment to public safety and are always willing to come to the community to present! (ie. Schools, Community Center, etc.)

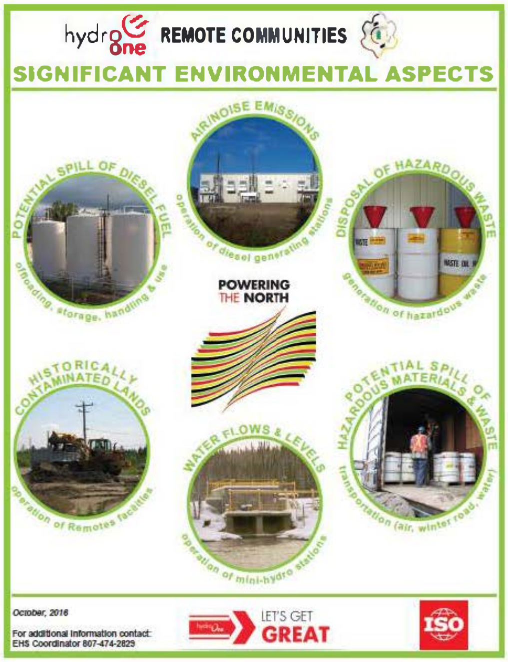
## Joint Use (Bell, Community Services, etc.)

- Poles have multiple uses. (Telephone, Cable, Internet, etc.)
- As owner/operator of the poles we have to ensure safe and proper use.
- Regulation 22/04 must be met. – Distribution Safety Standards
- All communities must have a joint use agreement in place in order to use poles.
- Joint use agreements set out the term and conditions related to standards, installation, maintenance and operation, emergency conditions, safety, etc.

## Environmental Commitment

- We are registered to ISO 14001 and take environmental protection very seriously
- The ISO 14001 Environment Management System (EMS) standard is an internationally recognized environmental management standard which is a systematic framework to manage the immediate and long term environmental impacts of an organization's products, services and processes.
- Our Environmental, Health, Safety, Management System (EHSMS) is integrated into all business operations.
- We also strive to the OHSAS 18001 Health and Safety standard.
- External, Internal and Compliance Audits are regular and independent of our business.

# Environmental Commitment




# Remotes - CaRE Program Initiatives

## Conservation and Renewable Energy Program

- Commercial Lighting Retrofit Program
- Mail-in Rebate Program
- Street Light Retrofit Program
- Renewable Energy Innovation DiEsel Emission Reduction (Reindeer) Initiative

## Renewable Energy - REINDEER

- Remotes is interested in enabling the connection of renewable energy projects to reduce the impact of diesel fuel on the environment within its service territory.
- In late 2012, the Remotes' **R**enewable **E**nergy **IN**novation **D**i**E**sel **E**mission **R**eduction (REINDEER) program was developed for projects of this nature.
- There are two (2) types of REINDEER projects:
  - "Standalone" projects will get paid for production
  - "Net Metering" projects will receive a reduced monthly bill.

## Renewable Energy: REINDEER in Action

Fort Severn

Wapekeka

Kingfisher

Kasabonika

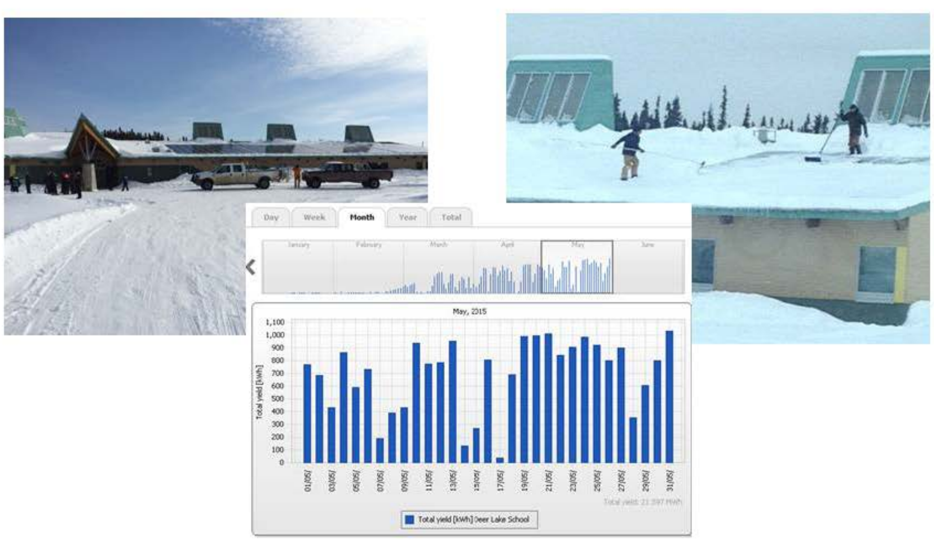
Armstrong

Weagamow

## Renewable Energy: REINDEER in Action

Deer Lake School – 130 kW


## Renewable Energy: REINDEER in Action




Net metering on the Deer Lake School saved $115,000 in the first year of operation.

## ROC – Remotes Outage Committee


## ROC – Why?

- Safe <u>Reliable</u> Power
- OEB and internal reliability targets
- Asset information
- Maintenance and planning
- Take a second look

## ROC – Who is involved

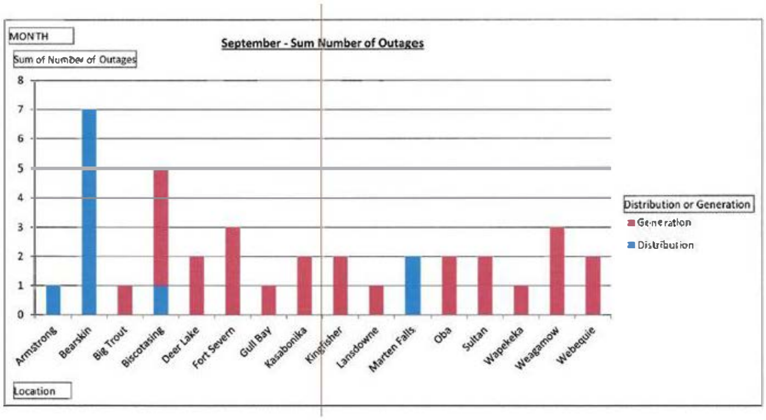
- Manager, Generation
- Manager, Customer Service
- Supt, DCAM (Engineering)
- FLM, Generation Mtce and Operations
- FLM, Lines and Customer Service
- Special guests

## ROC – What we do

- Review monthly performance
- Review significant outages – frequency/duration
- Discuss and troubleshoot
- Investigate and/or take action if required

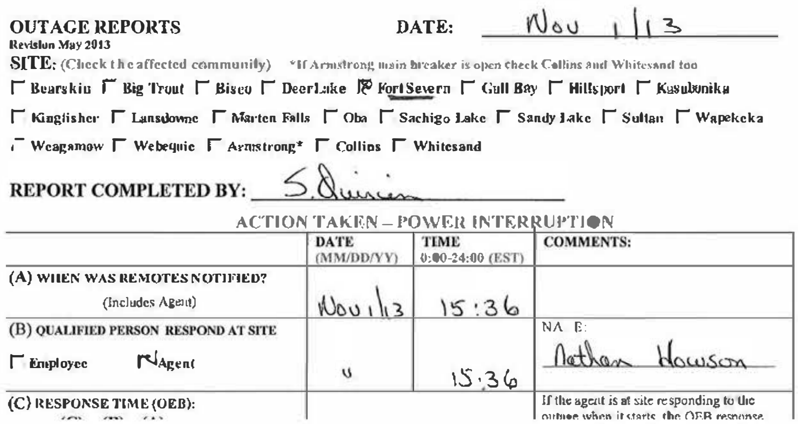
## ROC – What we do

- Review monthly performance - SQI




## ROC – What we do

- Get to the details



**OUTAGE REPORTS** **DATE:** Nov 1/13

Revision May 2013

**SITE:** (Check the affected community) *If Armstrong main breaker is open check Collins and Whitesand too

☐ Bearskin ☐ Big Trout ☐ Bisco ☐ Deer Lake ☑ Fort Severn ☐ Gull Bay ☐ Hillsport ☐ Kasabonika

☐ Kingfisher ☐ Lansdowne ☐ Marten Falls ☐ Oba ☐ Sachigo Lake ☐ Sandy Lake ☐ Sultan ☐ Wapekeka

☐ Weagamow ☐ Webequie ☐ Armstrong* ☐ Collins ☐ Whitesand

**REPORT COMPLETED BY:** S. Quinn

ACTION TAKEN – POWER INTERRUPTION

| | DATE (MM/DD/YY) | TIME 0:00-24:00 (EST) | COMMENTS: |
|---|---|---|---|
| (A) WHEN WAS REMOTES NOTIFIED? (Includes Agent) | Nov 1/13 | 15:36 | |
| (B) QUALIFIED PERSON RESPOND AT SITE ☐ Employee ☑ Agent | " | 15:36 | NA E: Nathan Howson |
| (C) RESPONSE TIME (OEB): | | | If the agent is at site responding to the outage when it starts, the OEB response |

## ROC – What we do

- Investigate - Review our action and response
  - Did we or our operator respond correctly?
  - Was the outage minimized?
  - Why does this keep happening?
  - Does further work need to be done?
  - How can we prevent in the future?

## ROC – Some Outcomes

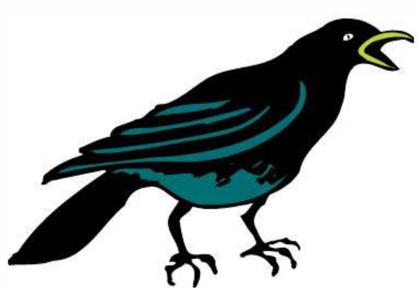
- Operator training
- Staff training
- Improved Customer interaction
- Asset maintenance and or repair
- Asset replacement
- Planning for the worst

## ROC – How are we doing?

| | | | Year to Date | | Status | | Year End | |
|---|---|---|---|---|---|---|---|---|
| | | | Actual | Target | YTD | Prior Status | Target | Projected |
| Operational Excellence | Maintain/Improve System Reliability[1] | System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point | 10.9 | 9.3 | ▲ | ▲ | 10.5 | ▲ |
| | | System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point | 9.6 | 11.3 | ★ | ★ | 12.0 | ● |
| | | Percentage of Generation Availability | 99.3% | 99.2% | ● | ● | 99.2% | ● |

## ROC – Going Forward

- Improved outage reporting/explanations
- Planning for planned outages
- Continued asset investment
- Safe <u>Reliable</u> Power



## Asset Investment: Viper Switch

## Asset Investment: New Engines

## Asset Investment: Transformers & Poles


## TSSA Audit:

- Signs of rust around the tank. (Clause 8.7.3.8 of code B139.1.0)

## ESA Inspections:

Report No. S20418850-N59-001

Electrical Safety Authority

Phone: 1-877-854-0079
Fax: 905-712-7886
CSS.ContactUs@electricalsafety.on.ca

155 Matheson Blvd. West
Mississauga, Ontario, L5R 3L5

### Continuous Safety Services
### Site Visit Report

The electrical systems of the

that inspection are identified on this report. In addition, you will also find an Outstanding Defect Report attached that outlines electrical defects that are still in our records as uncorrected. Please advise Derek Hertz once you have corrected any defects that were found.

site listed below were inspected on 20

| Customer Information | Site Information |
|---|---|
| HYDRO ONE REMOTE COMMUNITIES INC | SACHIGO GS AND HOUSE |
| 680 BEAVERHALL PL<br>THUNDER BAY, ON<br>Attn: KRAEMER COULTER | FLY IN COMMUNITY<br>SACHIGO, ON<br>Attn: CLARK LEMAY |

Issue Date: 2016/09/16
Purpose of Visit: Inspection
Visit Contact:

Inspector Name: Derek Hertz
Inspector Cell #: 807-620-9346
Inspector Email: DEREK.HERTZ@ELECTRICALSAFETY.ON.CA

**Recommendations**

| | | | | |
|---|---|---|---|---|
| 1 | Risk Factor N/A | Notification #: 20418850 Issue Date: 2016-09-16<br>Rule Reference: 82-004(a) No defects<br>Defect Location: | Defect Status: Completed<br>Defect #: 2 | Initial if corrected |

Code Rule: No defects were identified.

Inspector Comments:

**Thank you for giving us the opportunity to help you improve the safety of your facility. Your attention to these hazards, defects and recommendations will ensure continued safety on your premises. Should you have any questions regarding the items listed in this report, please do not hesitate to contact us.**

## Reg 22/04 Audits:

| | |
|---|---|
| 20 | 8" |
| 60 | 2'-0" |
| 150 | 5'-0" |

| PARTS LIST | | | | |
|---|---|---|---|---|
| PART No: | MM No: | DESCRIPTION | QUANTITY FIG.1 | QUANTITY FIG.2 |
| 1 | MM# | CONNECTOR, TAP, WEDGE | 4 | 2 |
| 2 | 30014480 | CONDUCTOR, BARE COPPER #4 | A/R | A/R |
| 3 | MM# | CONNECTOR, STIRRUP | 1 | 2 |
| 4 | 30006195 | CONNECTOR, LIVE LINE | 3 | 3 |
| 5 | MM# | INSULATOR, STANDOFF | 3 | 1 |
| 6 | 30000770 | CLAMP, REST | 2 | 1 |
| MM# - REFER TO SECTION 16 ONLY | | A/R - AS REQUIRED | | |

NOTES:
1. FOR TRANSFORMER INSTALLATION AND PARTS LIST SEE DL9-103.
2. FOR SINGLE PHASE INSTALL REMOVE FIELD & ROAD SIDE TRANSFORMERS & CONNECT TO DESIRED PHASE.
3. SEE DL9-107.1 FOR APPLICABLE FRAMINGS.

REFERENCES:
SECTION 3 – FRAMING
SECTION 4 – POLES
SECTION 5 – ANCHORING AND GUYING
SECTION 6 – VOLTAGES, LINE LOCATIONS AND CLEARANCES
SECTION 7 – CONDUCTORS AND CONNECTORS
SECTION 8 – OVERCURRENT PROTECTION AND SWITCHING
SECTION 10 – REGULATORS AND CAPACITORS
SECTION 11 – SERVICES & METERING
SECTION 12 – GROUNDING
SECTION 16 – MATERIALS LIST
COMPATIBLE UNITS MANUAL

ALL DIMENSIONS ARE IN CENTIMETRES UNLESS STATED OTHERWISE

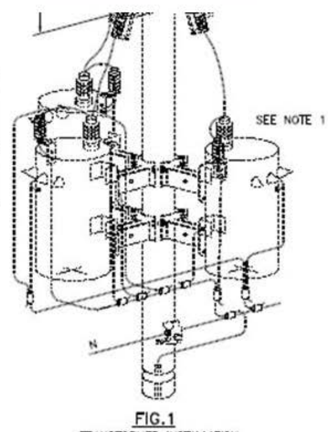



FIG.1
TRANSFORMER INSTALLATION ON DOUBLE CIRCUIT

| Rev. No. | Issue Date | Revision | Dsn/Chk | Approved By Date |
|---|---|---|---|---|
| 04 | OCT 2014 | REVD PARTS LIST. REFORMATTED DWG TO CAD STDS. | LS/PC | * |
| 03 | DEC 2012 | ADDED MM#, MIN. DIM. AND GENERAL REVISION | CJ/PC | * |



Hydro One Networks Inc.

Drawn: MV | Approved: * | Date: MAR. 26,2009

TRANSFORMER INSTALLATION, MULTI-CIRCUIT POLES 30kVA TO 501kVA, 3Ø, 2.4/4.16kV TO 16/27.6kV

Dwg. No. DL9-105 | Rev. 04

## Questions


---

Capital Planning and Upgrades

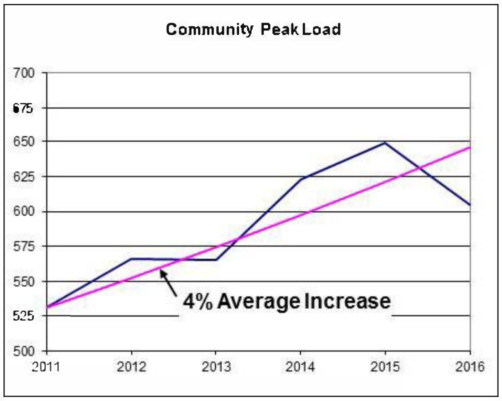
Ralph Falcioni
November 23, 2016

## Introduction

- Generation Overview
  - 19 Diesel Generating Stations
    - 14 serve First Nation communities
  - Supplemental Generation
    - 2 Hydroelectric Generating Stations
    - 4 Windmills

## Introduction Cont'd

- First Nation communities have steady load growth
- Growth varies community to community (1% to 6%)
- Upgrades required every 7-10 years



## Capital Planning

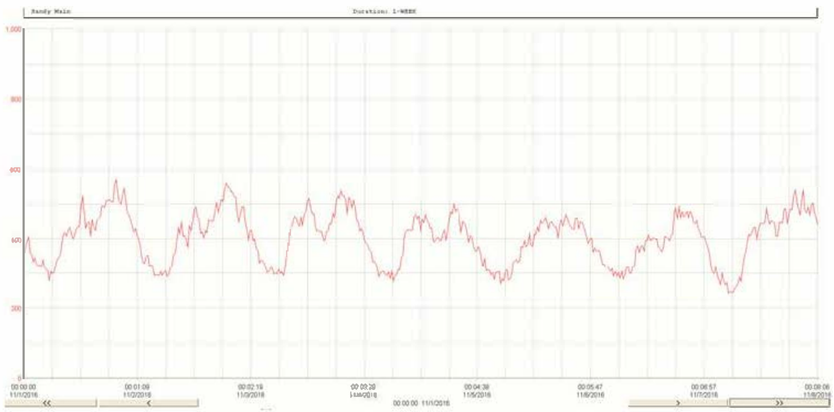
- Station Rating
- Community Demand Data

## Station Rating

- Stations have either 3 or 4 generators
- Determine the station capacity – formulas and operational experience
- Capable of supplying community with at least one major failure

## Community Demand Data

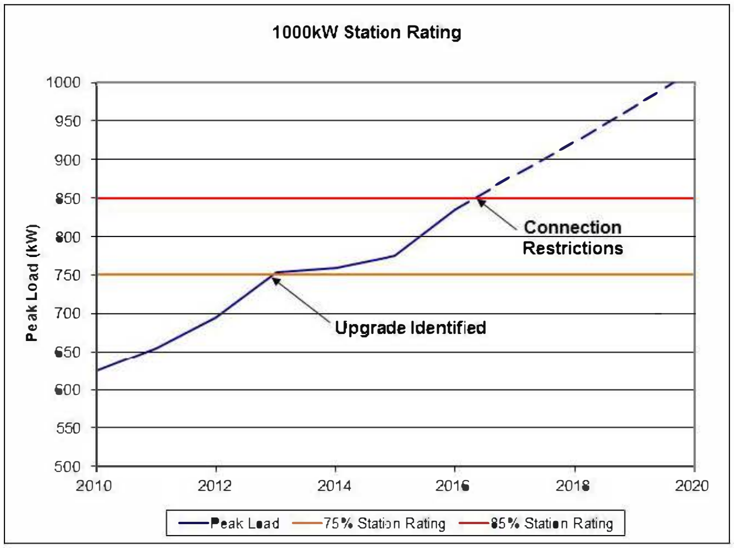
- SCADA system records main breaker output
- Peak load is compared to station rating



## Community Demand Data Cont'd

- At 75% of station rating, First Nation is informed about future need for capacity increase.
- At 85% of station rating, connection restrictions are imposed to protect the reliability of electrical supply to existing customers
  - New and upgraded connections are not allowed until station is upgraded

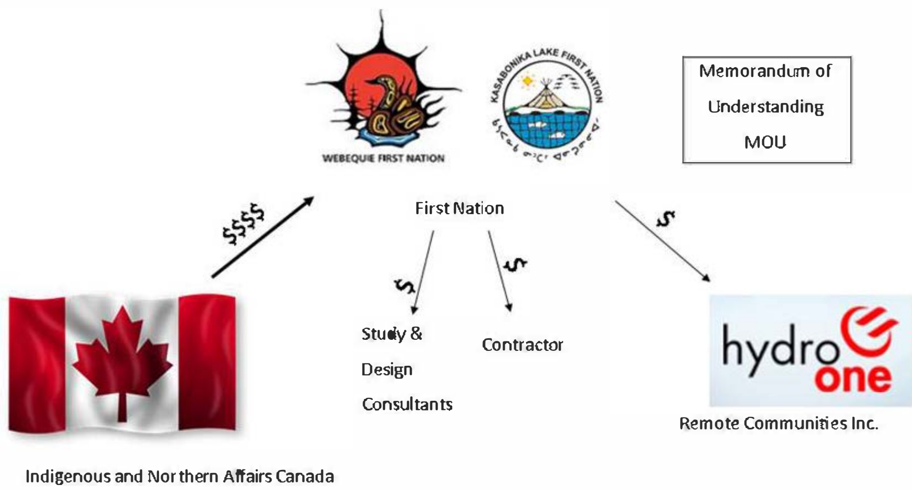
## Typical Load Growth & Thresholds




## Upgrades

- Old Process
- New Process
- Station Design Overview
- Station Guidelines
- Current and Future Upgrades

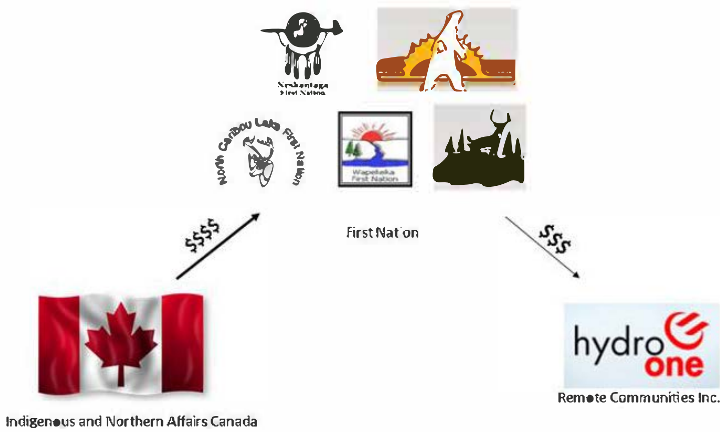
## Old Process




## Old Process Cont'd

- Upgrade can be completed in as little as 7 years
- Duplication of some work done by consultant and contractor

## New Process




## New Process Cont'd

- Upgrade can be completed in as little as 1 year
- Work more closely with community to find innovative solutions (i.e. tie-line, net metered solar)
- Design standardization in controls

## New Process Cont'd

## New Process Success

Completed Upgrades

- Neskantaga 2014
- Fort Severn 2015
- Deer Lake 2015
- Wapekeka 2015
- North Caribou 2016

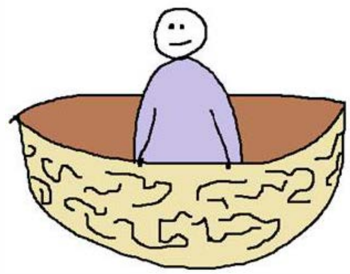
## New Process Success

Planned Upgrades

- Kingfisher Lake – 2017
- KI – Wapekeka – 2018
- North Caribou Phase 2 - 2019

## Questions?

## In a nutshell …



## Recap

Total System Management Everything is looked after … the operation, maintenance, logistics, regulatory and financial aspects of the Distribution and Generation systems, including fuel!

Seamless transition to Transmission

- We will look after everything
- We even have a backup solution readily available, unlike the IPAs

Customer and Community Programs

- Provide conservation, public safety, and community sponsorship programs

Operator and Meter Readers

– Pay for and train

## Recap

### Collections

- OEB and rate payers demand it, and so would any store owner
- IPAs have to collect in order to pay for fuel and maintenance
- Rate payers put in $2 for every $1 collected

### Safe Reliable Power

- 24/7 coverage for generation or distribution issues
- Canadian top quartile generation reliability - **99.998%** in 2015

### Lifetime Warranty

- On all in-service equipment i.e. engines, transformers, poles, etc.

### Lowest residential energy rates in Ontario

## Please ask us

# Report on Customer Service Research

*Prepared for Hydro One Remote Communities*

August 2017

**Viewpoints Research**
Winnipeg, Manitoba
(204) 988-9253
www.viewpoints.ca

# TABLE OF CONTENTS

# EXECUTIVE SUMMARY

On behalf of Hydro One Remote Communities, Viewpoints Research conducted a telephone survey of 150 of its residential, business and government-supported organization customers from May 3 to June 24, 2017.

Where possible, the survey tracks findings from six previous waves of customer surveys conducted approximately every two years since 2003.

## Satisfaction with Electricity Service

Overall satisfaction with the electricity service customers receive from Hydro One Remotes, is 90%, similar to levels recorded in 2015, 2011 and 2009 but down from 97% recorded in 2013.

## Reasons for Customer Satisfaction

Among customers who are satisfied with their electricity service, having electricity available when they want it, and having had no problems with their Hydro service, continues to be the main driver of satisfaction with Hydro One electricity service (71%).

Approximately one in four customers attributed their satisfaction to good or improved service (14%) or improved reliability (12%). Satisfaction with customer service is mentioned by 7% of customers.

## Reasons for Customer Dissatisfaction

There were 11 dissatisfied customers in this research. At least eight customers mentioned that rates are high (73%), rates are discriminatory or unfair (9%) or that their bill is confusing (9%) as reasons they are not satisfied. Three customers mentioned service-related reasons, including power not being reliable (18%) and brownouts and problems with appliance (9%). Other reasons given are: the service is bad for the environment, smelly or dirty (18% or 2 mentions) and their community is hurt by the service (9% or 1 mention).

## Billing Accuracy

Two thirds of the customers interviewed were the person in their household who usually pays the Hydro bill (67%), while 3% said sometimes and 31% said no.

Of those who pay the bill usually or sometimes, perceptions regarding the overall accuracy of Hydro One's billing has dropped somewhat over the past two waves of research.

In total, 7% of customers said their bills were either not correct very often (4%) or never correct (3%). One in four respondents were unsure how to answer this question (25%).

## Rates vs. Rest of Ontario

Two thirds of Hydro One Remotes customers believe their Hydro rates are either the same as the rest of Ontario (30%) or higher (35%), while three in ten are unsure (29%). Just 7% of customers believe their rates are lower.

## Preferred Bill Payment Method

Customers were presented with five ways they could pay their Hydro bill and asked to select their one preferred method. A majority of respondents did not select any one of the responses. One in four said ‘none of the above’ (25%), 21% offered another means of payment or said ‘more than one’ and 7% were unsure.

Of the five options presented, a money gram or money order is the choice of 16% of customers, 14% chose a pre-paid credit card, 9% prefer paying online using a credit card, 5% like to use a cheque and 4% prefer to pay cash.

## Incidence of Customer Contact

Almost half of customers said they contacted Hydro One in the past year (49%). As in previous years, the most common reason customers contacted the utility was to discuss their bill (31%). Other reasons for contact include customers needing information (17%) and the power being out (15%).

## Satisfaction with Customer Contact

Among customers who called Hydro One Remotes, satisfaction with how the utility handled their contact rebounded to 85%, falling just short of 2013’s record high of 88%. This includes almost half of customers who said they were very satisfied with their contact with Hydro One (45%).

## Drivers of Service Satisfaction

This research tested customers’ agreement with three statements related to customer service, to explore customers’ experiences and perceptions in key service areas. Hydro One Remote Communities scored best at *dealing with emergencies* (82% agree overall) and *staff being polite and friendly* (79%). Customers were less likely to agree that *when they call the Hydro One office someone usually answers quickly.*

## Number of Calls Needed

Of those who remember calling the office, a majority of customers said their question or concern was resolved the first time they called Hydro, while 18% said an additional call was required..

## Awareness of Local Operators

Two thirds of customers know who their local Hydro One operator is (65%), at its second highest level since tracking began. One third do not know who their operator is (35%).

## Awareness of Meter Readers

Seven in ten respondents know who their meter reader is (70%), its second highest level over five waves of tracking. One in three customers admitted they do not know their local meter reader (30%).

## Contact During Outages

A majority of customers do not call anyone when there is an outage (54%). One in eight call the emergency hotline (13%), while fewer call the operator (11%) or the Band Council Office (9%). Six percent (6%) call the phone number on their bill and 5% call the meter reader.

## Local Environmental Protection

About six in ten Hydro One Remotes customers said the utility takes environmental protection in the community seriously (58%). About one in ten said Hydro One does not take it seriously (10%). One third of respondents were unsure (32%).

## Renewable Electricity Generation

About three in ten customers were aware communities like theirs can generate renewable electricity through solar, wind or small hydro water projects and sell it back to Hydro One Remotes (31%), while 69% were not aware of this potential or were unsure.

## Investment in Renewable Energy

Two thirds of customers hold the view that Hydro should invest more in renewable energy (65%), while 11% said no or were unsure and 25% declined to answer the question.

## Electricity Rebates & Programs

Most Hydro One Remotes customers were not aware of various electricity-related rebates and programs available to them.

### *Appliance Rebates*

More than one third of customers are aware they can receive rebates up to $200 when they buy energy-efficient appliances (35%).

### *LEAP & OESP*

Awareness has jumped regarding the Low-Income Emergency Assistance Program (LEAP) to 33%, while one in four is aware of the Ontario Electricity Support Program (OESP) (25%).

# GOALS & METHODOLOGY

## Goals

On behalf of Hydro One Remote Communities, Viewpoints Research conducted telephone interviews with the utility's residential, commercial and government-supported organization customers from May 3 to June 24, 2017. Many of the questions included in this survey have been tracked from earlier customer surveys administered about every two years since 2003. The research explored the following:

- Customers' views on the accuracy of their bills,
- Recent contact with Hydro One and satisfaction with the contact,
- General perceptions of Hydro responsiveness and customer service,
- Customers' preferred method of bill payment,
- Awareness of local Hydro One staff,
- Perception of Hydro rates compared to elsewhere in Ontario,
- Awareness of electricity-related rebates and programs,
- Perceptions of Hydro One's commitment to environmental protection in their communities,
- Views on local generation of renewable electricity sources and Hydro's role in the development of renewable energy sources, and
- Overall satisfaction with the electricity service provided by Hydro One, and reasons for their satisfaction or dissatisfaction,

## Methodology

Sample was drawn from listed and unlisted telephone numbers in the Hydro One Remote Communities' service area. Hydro One Remote Communities has about 3,500 customers in 21 communities. This year 150 customers were interviewed, including 147 residential customers, 2 business customers and 1 government-supported organization. The survey has an overall confidence level of ±7.8%, nineteen times out of twenty.

The findings of this research were cross tabulated by the following demographic and attitudinal variables:

- Community,
- Main heat source,

- Type of service (residential, commercial or government-supported organization),
- Satisfaction with electrical service,
- Whether or not customers have contacted Hydro One in the last year,
- Gender, and
- Age.

## Reporting

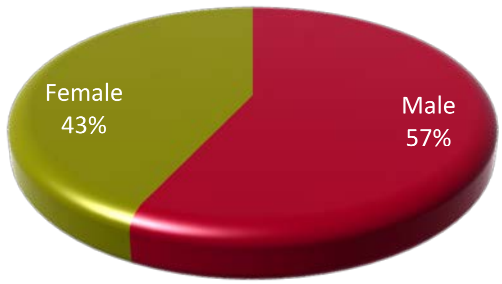
This report highlights the overall views and perceptions of Hydro One Remote Communities customers. When the attitudes of a particular set of customers is statistically different from customers overall, this will be noted in the report in a bulleted point. The report also compares the findings to results from seven previous waves of research conducted every two years since 2003.

There are significant differences of opinion among residents of the different communities served by Hydro One Remote Communities, however these results should be interpreted with caution since the number of respondents in most communities is very small. Caution should be applied, generally, when considering differences among sub-groups with fewer than 100 respondents.

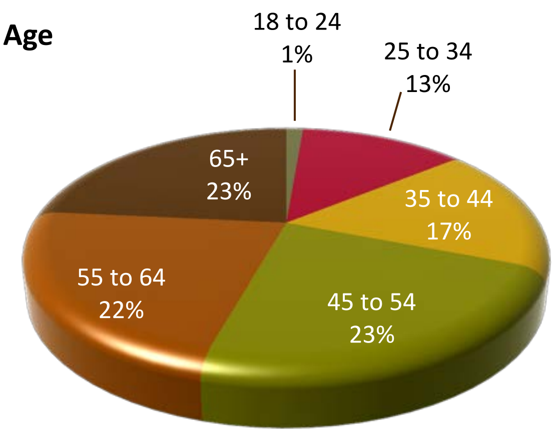
# RESPONDENT PROFILE

The following charts provide an overview of respondents interviewed for this wave of research.

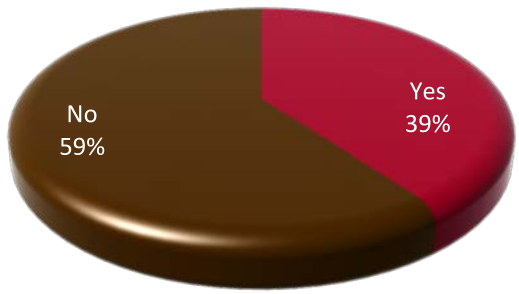
**Gender**



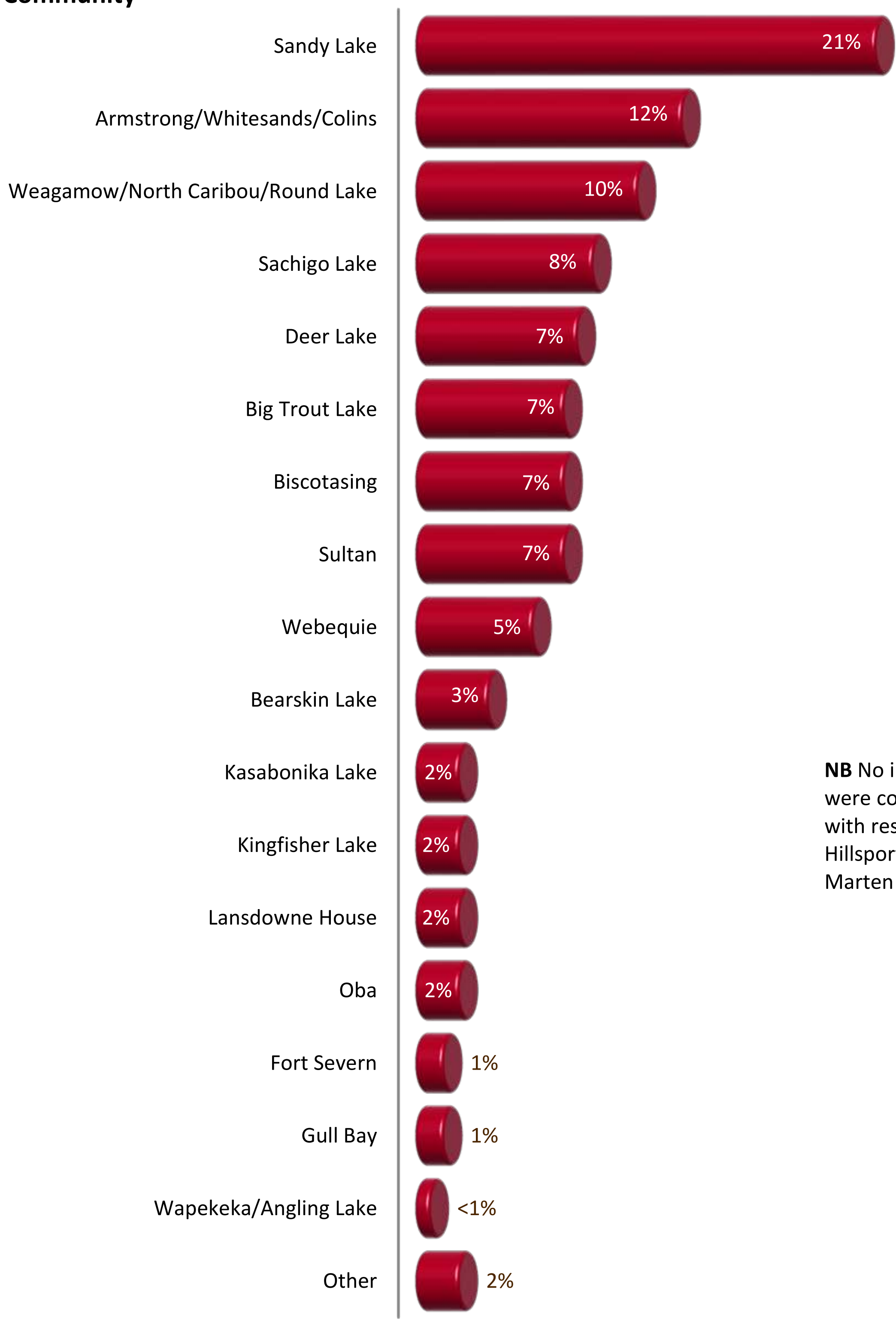

**Age**



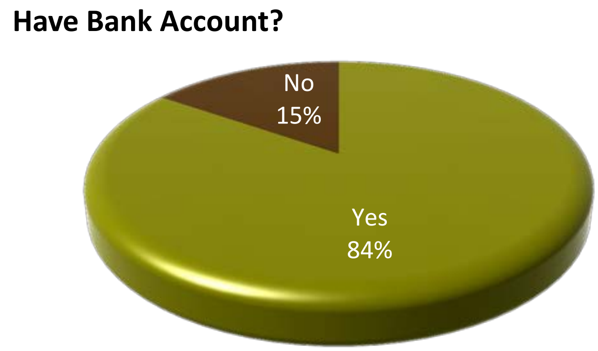

**Heat with Electricity?**



## Community




**NB** No interviews were completed with residents in Hillsport or Marten Falls.




## Respondents Over Time

The following table summarizes the demographic attributes of all respondents participating in the research since 2003. The characteristics of customers participating in this research have generally remained consistent over time.

**Respondent Over Time**

| Respondent Profile | 2017 | 2015 | 2013 | 2011 | 2009* | 2007 | 2005 | 2003 |
|---|---|---|---|---|---|---|---|---|
| **Customer Type** | | | | | | | | |
| Home | **98%** | 91% | 82% | 89% | 87% | 81% | 82% | 96% |
| Business | **1%** | 4% | 10% | 5% | 7% | 6% | 8% | 2% |
| Gov't-funded | **<1%** | 6% | 9% | 6% | 6% | 13% | 10% | 2% |
| **Age** | | | | | | | | |
| 18 – 24 years | **1%** | 7% | 8% | 6% | 8% | 13% | 10% | 13% |
| 25 – 34 years | **13** | 15% | 15% | 17% | 20% | 26% | 23% | 22% |
| 35 – 44 years | **17%** | 12% | 19% | 19% | 21% | 24% | 28% | 26% |
| 45 – 54 years | **23%** | 23% | 26% | 21% | 21% | 20% | 23% | 21% |
| 55 – 64 years | **22%** | 22% | 16% | 22% | 19% | 11% | 10% | 11% |
| 65 years and older | **23%** | 22% | 15% | 15% | 11% | 5% | 4% | 7% |
| **Gender** | | | | | | | | |
| Men | **57%** | 54% | 50% | 56% | 60% | 54% | 56% | 54% |
| Women | **43%** | 46% | 50% | 44% | 40% | 46% | 44% | 46% |

Tallies may not equal 100%. Customers who were unsure are not included.
*Research conducted in 2009/2010 is reported as 2009 in this document.

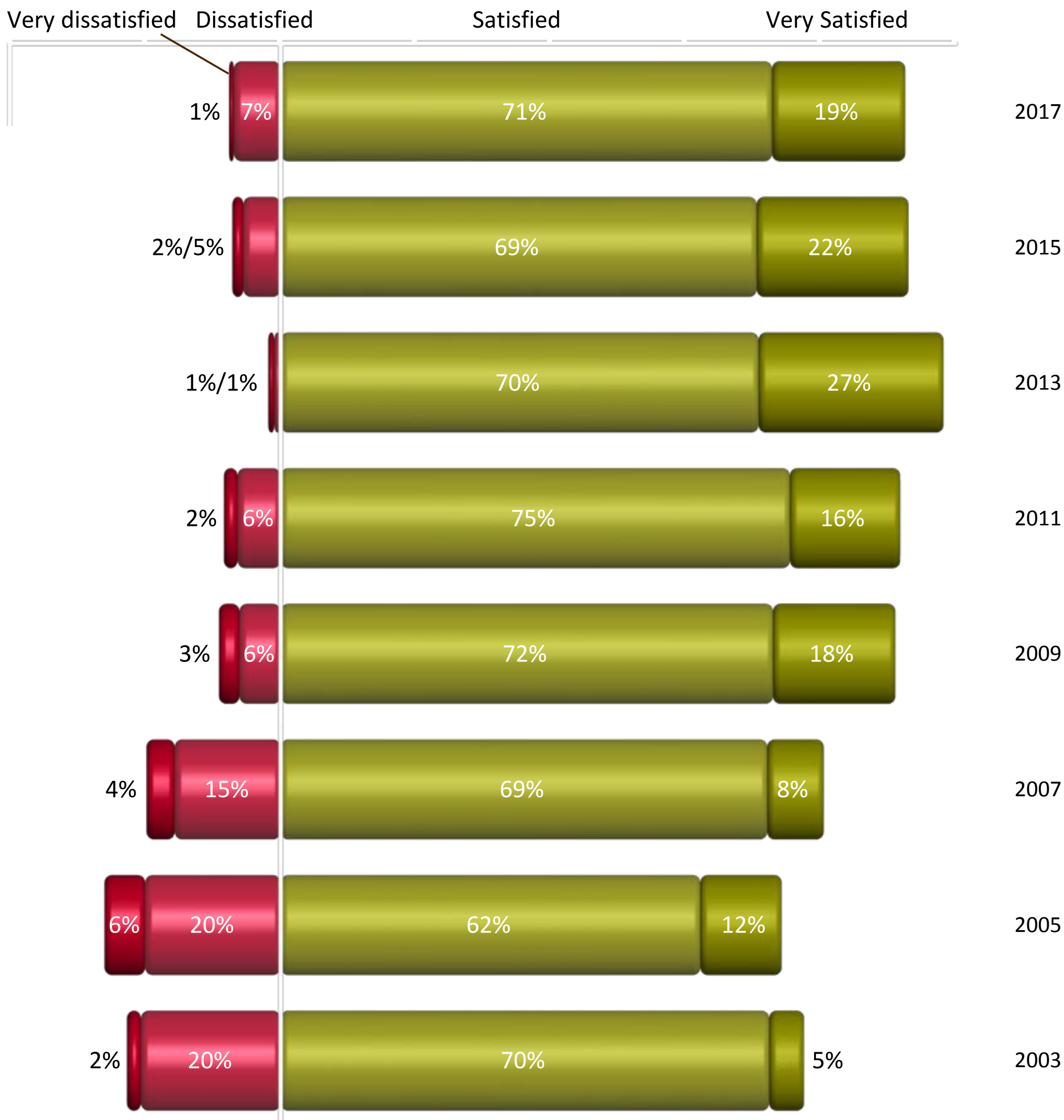
# RESEARCH FINDINGS

## Satisfaction with Electricity Service

### *Overall Satisfaction with Service (Q23)*

Overall satisfaction with the electricity service they receive from Hydro One Remotes, is 90%, similar to levels recorded in 2015 (91%), 2011 (90%) and 2009 (91%) but down from 97% recorded in 2013.

Chart 1: **Satisfaction with Electricity Service**



### *Reasons for Customer Satisfaction* (Q24)

Among those who are satisfied with their electricity service (n=135), having electricity available when they want it, combined with customers who indicate they have had no problems with their Hydro service, continues to be the main driver of satisfaction with Hydro One electrical service (71%) up 6 points since 2015, 11 points since 2013 (51%) and 25 points since 2009 (40%).

Approximately one in four customers attributed their satisfaction to good or improved service (14%) or improved reliability (12%). Satisfaction with customer service is mentioned by 7% of customers.

Chart 2 displays all the reasons for satisfaction mentioned by customers and Table 1 compares this year's results to past waves of research.

Chart 2: **Reason for Customer Satisfaction** (n=135)

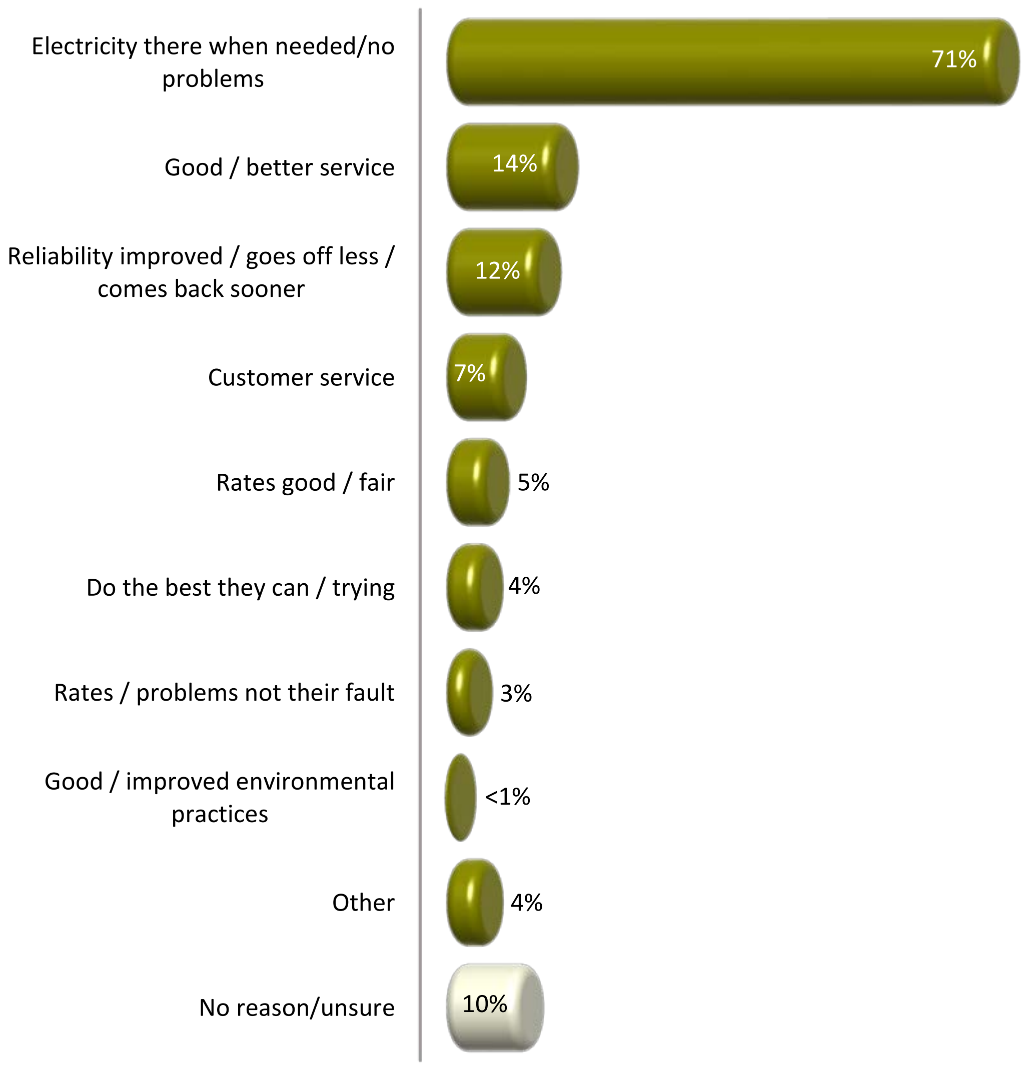


Table 1: **Reasons for Customer Satisfaction**

| Reason | 2017 | 2015 | 2013 | 2011 | 2009 | 2007 | 2005 | 2003 |
|---|---|---|---|---|---|---|---|---|
| Electricity there when needed/no problems | **71%** | 65% | 51% | 49% | 40% | 42% | 43% | 43% |
| Good/improved service | **14%** | 20% | 15% | 26% | 18% | 20% | 19% | 19% |
| Reliability has improved | **12%** | 12% | 17% | 25% | 20% | 12% | 10% | 10% |
| Customer service | **7%** | 10% | 10% | 11% | 13% | 3% | 4% | 4% |
| Fair rates | **5%** | 4% | 6% | 10% | 5% | 5% | 6% | 6% |
| Company doing the best they can | **4%** | 4% | 2% | 6% | 5% | 3% | 4% | 4% |
| Rates/problems not their fault | **3%** | 1% | NA | NA | NA | NA | NA | NA |
| Environmental practices | **<1%** | 0% | 1% | 2% | 2% | <1% | 1% | 1% |
| No reason/other/unsure | **14%** | 12% | 19% | 10% | 27% | 26% | 26% | 26% |

Percentages do not total 100% because customers were permitted more than one response.

### *Reasons for Customer Dissatisfaction* (Q25)

There were 11 dissatisfied customers in this research. Ten customers mentioned that rates are high (73%), rates are discriminatory or unfair (9%) or that their bill is confusing (9%) as reasons they are not satisfied. Three customers mentioned service-related reasons, including power not being reliable (18%) and brownouts and problems with appliance (9%). Other reasons given are: the service is bad for the environment, smelly or dirty (18%, 2 mentions) and their community is hurt by the service (9%, 1 mention). One customer offered another reason (9%) and one did not provide a response (9%).

Chart 3 displays the reasons for dissatisfaction mentioned by customers and Table 2 compares this year's results to past waves of research.

Chart 3: **Reason for Customer Dissatisfaction** (n=11)

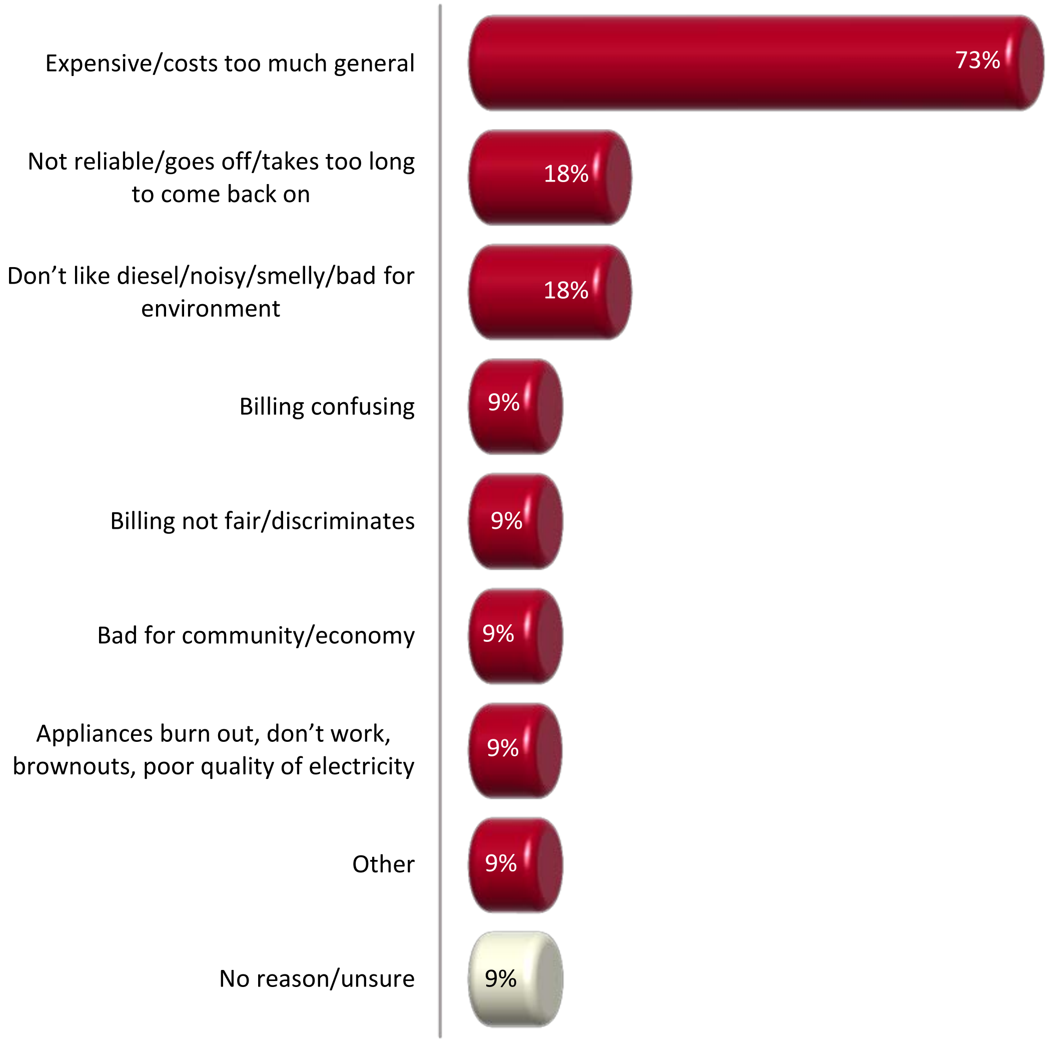


Table 2: **Reasons for Customer Dissatisfaction**

| Reasons for dissatisfaction | 2017 | 2015 | 2013 | 2011 | 2009 | 2007 | 2005 | 2003 |
|---|---|---|---|---|---|---|---|---|
| **Rates** | | | | | | | | |
| Expensive/high rates | **73%** | 85% | 50% | 56% | 48% | 64% | 73% | 63% |
| Rates discriminatory/unfair | **9%** | NA | 25% | 8% | 4% | 9% | 14% | 13% |
| Bill is confusing | **9%** | NA | 25% | 0% | 4% | 2% | 10% | 8% |
| **Service Issues** | | | | | | | | |
| Power not reliable | **18%** | 31% | 50% | 20% | 15% | 22% | 21% | 23% |
| Power quality problems, brownout/problems with appliances | **9%** | 8% | 25% | 4% | 11% | 5% | 7% | 21% |
| **Other** | | | | | | | | |
| Bad for environment/smelly/noisy | **18%** | NA | 50% | 4% | 0% | 0% | 1% | 0% |
| Community/economy hurt by service/company | **9%** | NA | 25% | 0% | 0% | 2% | 2% | 2% |
| Don't like Hydro One | **NA** | NA | NA | 0% | 5% | 5% | 8% | 3% |
| No reason/other | **9%** | 23% | NA | 8% | 7% | 7% | 6% | 2% |

Percentages do not total 100% because customers were permitted more than one response.

## Hydro Billing & Rates

### *Billing Accuracy (Q3 & Q4)*

Two thirds of the customers interviewed were the person who usually pays the Hydro bill (67%), while 3% said sometimes and 31% said no.

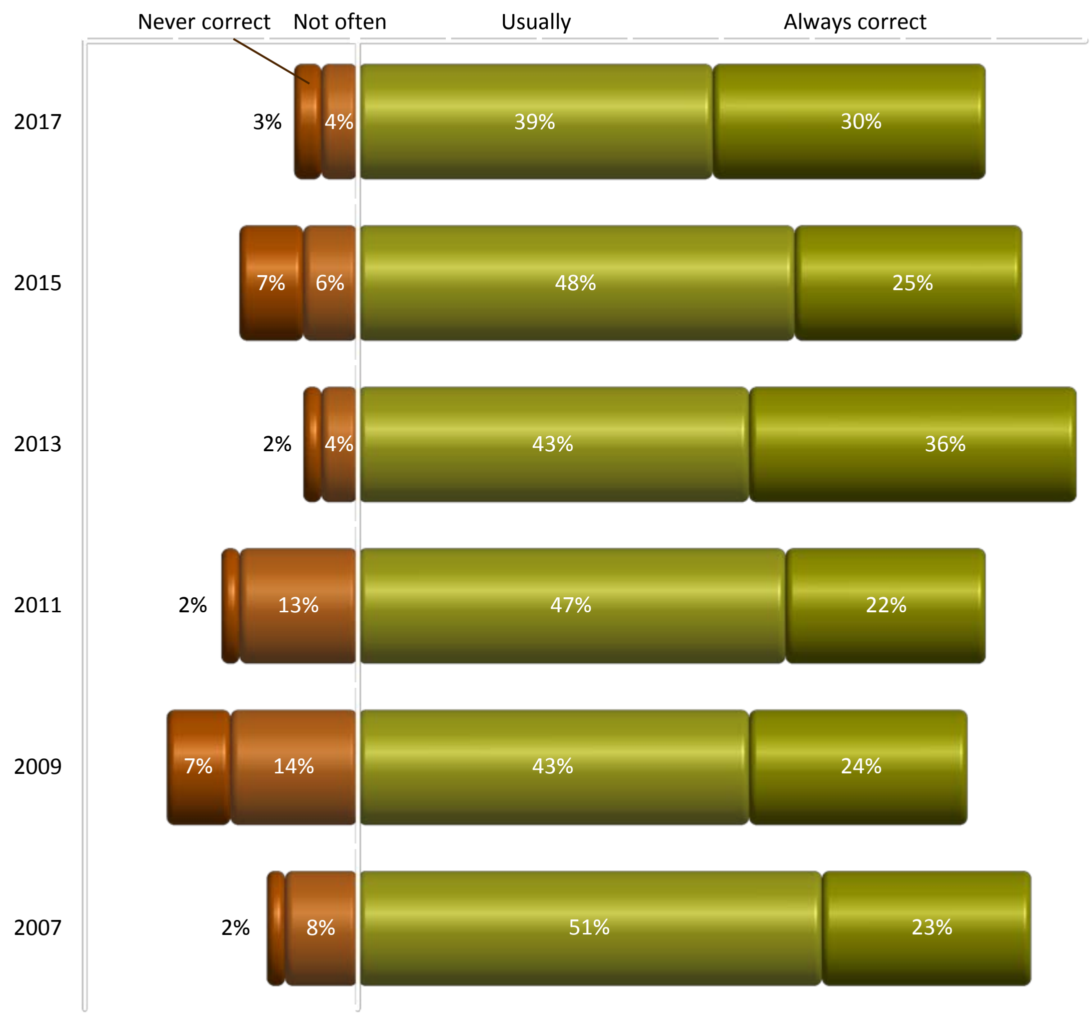
- The likelihood of paying the Hydro bill increases with age from 33% of 18 to 34-year-olds (21N) to 84% of those 55+ (68N).

Of those who pay the bill usually or sometimes (n=104), perceptions regarding the overall accuracy of Hydro One's billing has dropped somewhat over the past two waves of research to levels last seen in 2009 and 2011.

In this wave 30% said their Hydro One bill is always correct, up 5 points since 2015 and the second highest 'always correct' responses since tracking began. In addition, 39% of respondents said their bill is usually correct, down 9 points since 2015. In total, 7% of customers said their bills were either not correct very often (4%) or never correct (3%), down 6 points since 2015 and similar to 2013 results.

One in four respondents were unsure how to answer this question (25%), up 10 points since 2015.

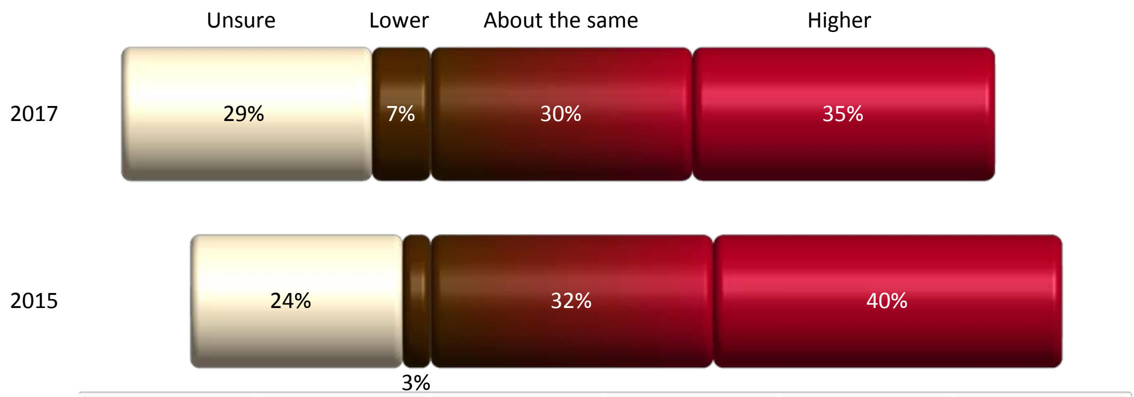
Chart 4: **Billing Accuracy**



### *Rates vs. Rest of Ontario* (Q16)

Two thirds of Hydro One Remotes customers believe their Hydro rates are either the same as the rest of Ontario (30%) or higher (35%), while three in ten are unsure (29%). Just 7% of customers believe their rates are lower. The perception that their rates are higher has dropped 5 points since 2015.

Chart 5: **Rates vs. Rest of Ontario**

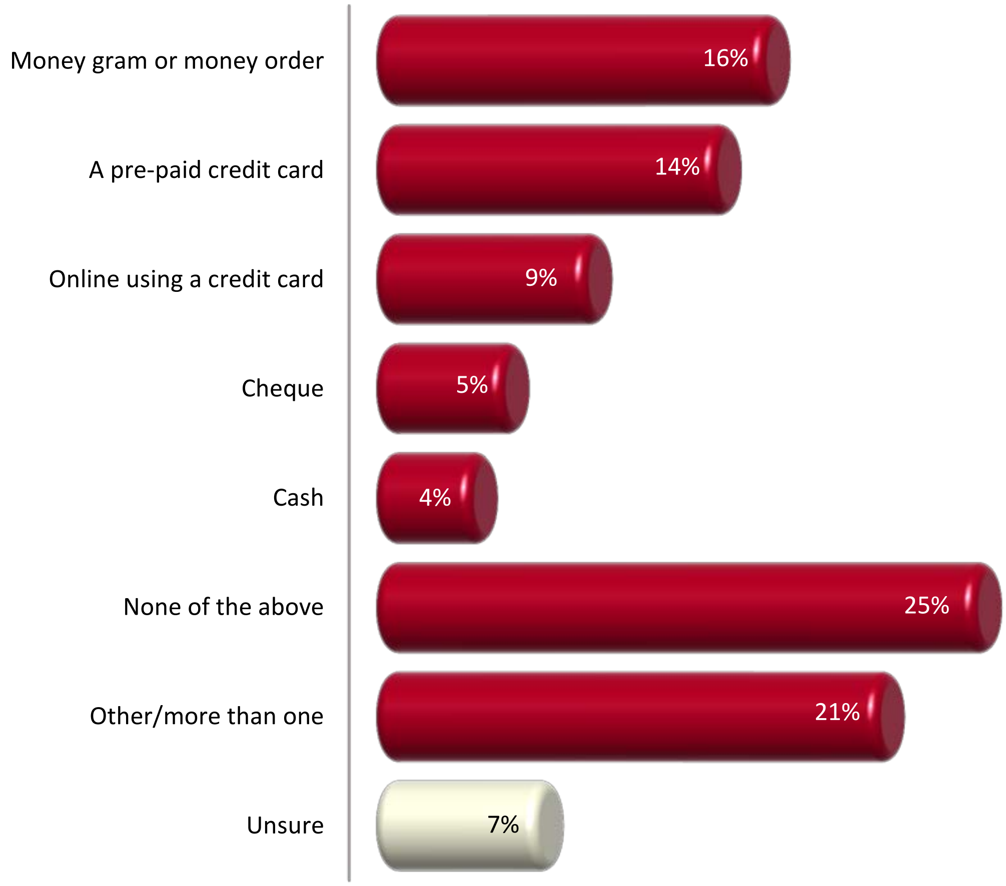



### *Preferred Bill Payment Method* (Q12)

Customers were presented with five ways they could pay their Hydro bill and asked to select their one preferred method. A majority of respondents did not select any of the responses. One in four said 'none of the above' (25%), 21% offered another means of payment or said 'more than one' and 7% were unsure.

Of the five options presented, a money gram or money order is the choice of 16% of customers, 14% chose a pre-paid credit card, 9% prefer paying online using a credit card, 5% use a cheque and 4% pay cash.

Chart 6: **Preferred Bill Payment Method**




## Customer Contact

### *Incidence of Contact (Q5)*

Almost half of customers said they contacted Hydro One in the past year (49%) compared to 42% in 2015, 38% in 2013 and 44% in 2011. As in previous years, the most common reason customers contacted the utility was to discuss their bill (31%, up 5 points since 2015). Other reasons for contact include customers needing information (17%, as in 2015) and the power being out (15%, up 6 points).

Chart 7 summarizes 2017 responses and Table 3 compares current responses to previous waves of research.

Chart 7: **Incidence of Contact**

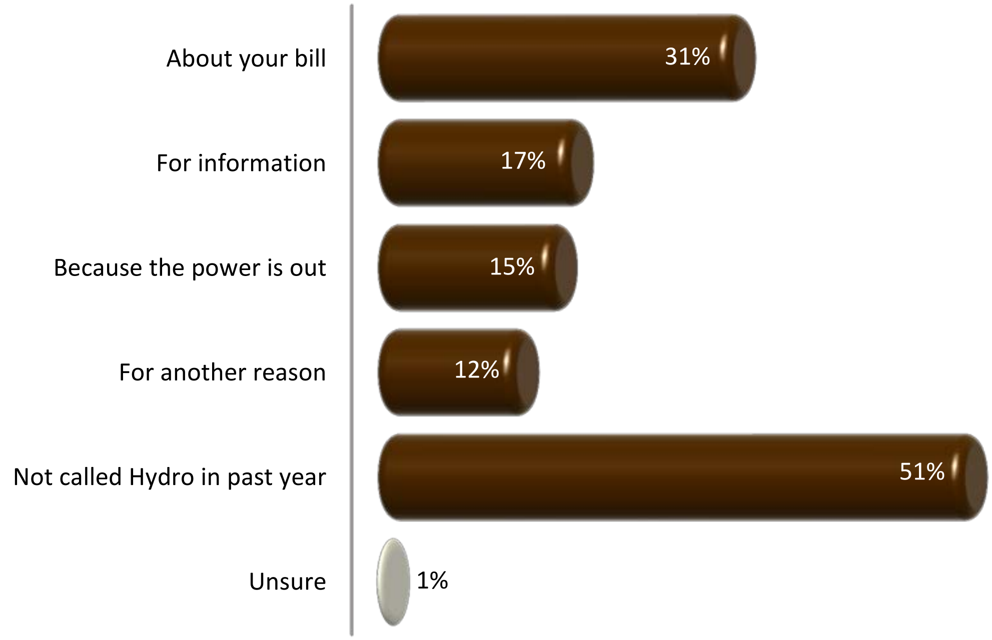



Table 3: **Incidence of Contact Over Time**

| Nature of Inquiry | 2017 | 2015 | 2013 | 2011 | 2009 |
|---|---|---|---|---|---|
| About your bill | **31%** | 26% | 19% | 24% | 20% |
| For information | **17%** | 17% | 12% | 13% | 18% |
| Because power was out | **15%** | 9% | 11% | 15% | 15% |
| Another reason | **12%** | 13% | 9% | 10% | 9% |
| Have not called Hydro One in past year | **51%** | 58% | 62% | 54% | 57% |
| Don't recall | **1%** | 0% | 1% | 2% | 2% |

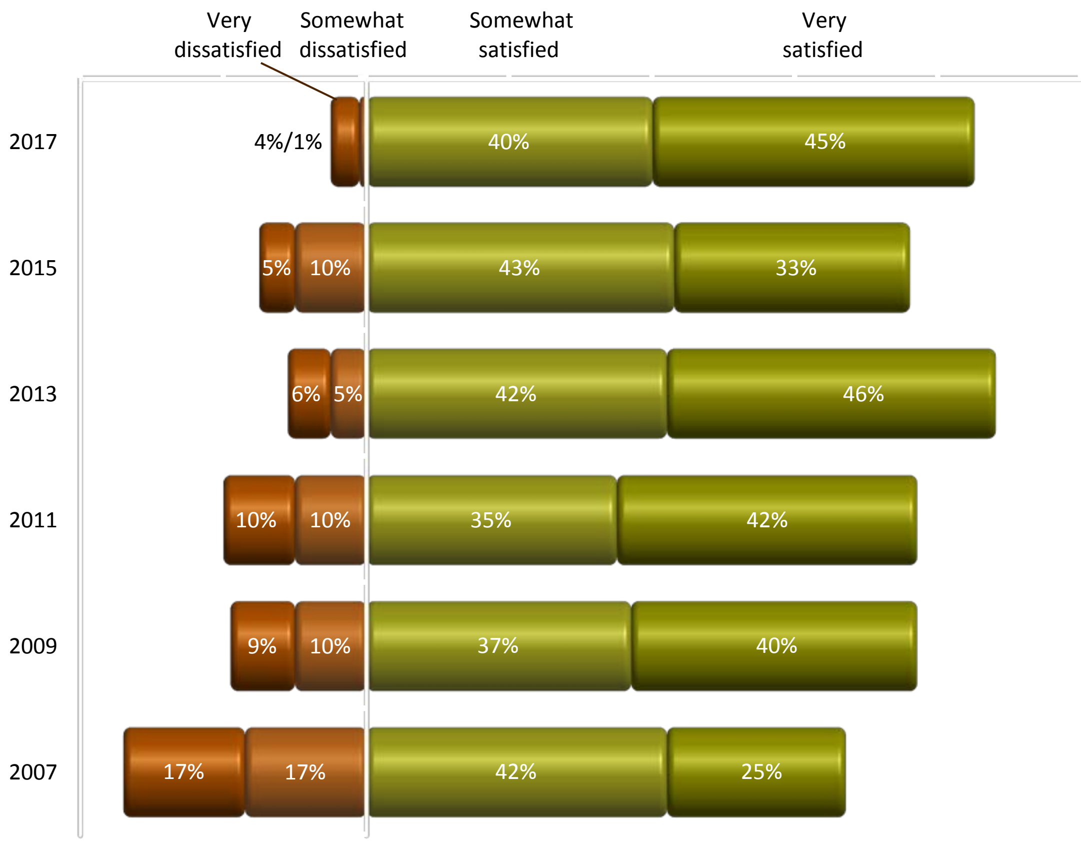
Percentages do not total 100% because customers were permitted more than one response

### *Satisfaction with Customer Contact (Q6)*

Among customers who called Hydro One Remotes (n=73), satisfaction with how the utility handled their contact rebounded to 85%, up 9 points over 2015 results, falling just short of 2013's record high of 88%. This includes almost half of customers who said they were very satisfied with their contact with Hydro One (45%, up 12 points since

2015). Current results represent the second highest satisfaction rating since tracking this question began in 2007.

Chart 8: **Satisfaction with Customer Contact**




- Overall satisfaction with Hydro Remotes correlates with customers' satisfaction with their recent contact.

### ***Drivers of Service Satisfaction*** *(Q7 - Q9)*

This research tested customers' agreement with three statements related to customer service, to explore customers' experiences and perceptions in key service areas. Hydro One Remote Communities scored best at *dealing with emergencies* (82% agree overall) and *staff being polite and friendly* (79%). Customers were less likely to agree that *when they call the Hydro One office someone usually answers quickly,* though a majority still agree (60%).

Agreement with these statements rebounded somewhat but still remains among the lowest ratings recorded since 2009.

Chart 9 summarizes 2017 responses and Table 4 compares current responses with past waves of research.

Chart 9: **Drivers of Service Satisfaction**

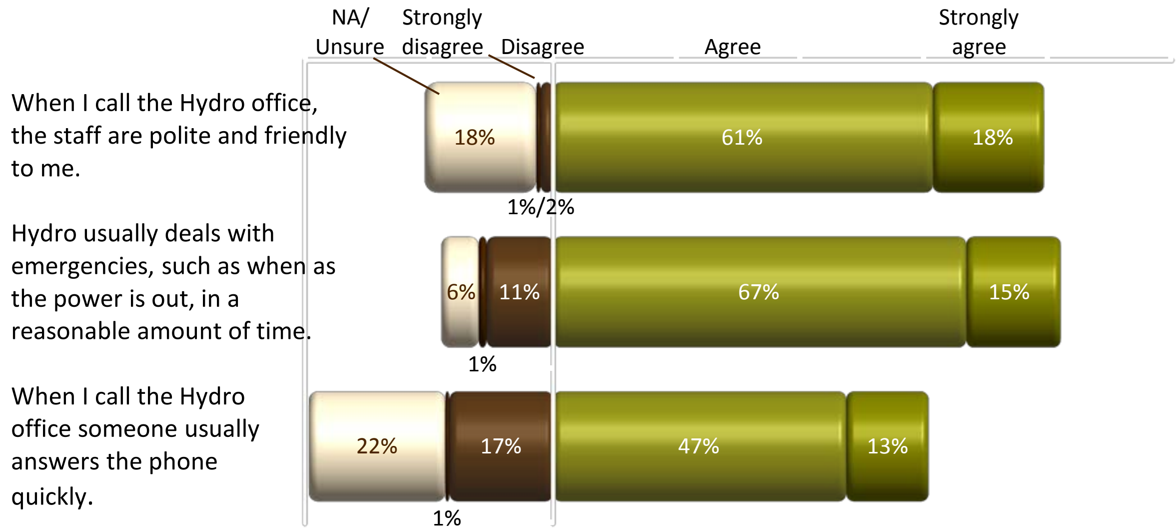



Table 4: **Drivers of Service Satisfaction**

| Statement | 2017 | 2015 | 2013 | 2011 | 2009 |
|---|---|---|---|---|---|
| Hydro One usually deals with emergencies, such as when the power is out, in a reasonable amount of time. | **82%* (15%)** | 80% (15%) | 88% (18%) | 85% (20%) | 86% (18%) |
| When I call the Hydro One office, the staff are polite and friendly to me. | **79% (18%)** | 75% (17%) | 80% (20%) | 80% (18%) | 80% (20%) |
| When I call the Hydro One office someone usually answers the phone quickly. | **60% (13%)** | 62% (11%) | 65% (11%) | 61% (12%) | 68% (12%) |

*Unbracketed percentages combine agree and strongly agree responses, bracketed percentages are strongly agree responses only.

Percentages do not total 100% because those who were unsure are not included.

- Among communities with 10 or more respondents, Biscotasing (100%) and Sultan (90%) are most likely to agree that Hydro deals with emergencies in a reasonable amount of time, while Big Trout Lake/KI are least likely to (70%).

### ***Number of Calls Needed*** *(Q10)*

Of those who remember calling the office, a majority of customers said their question or concern was resolved the first time they called , while 18% said an additional call was required.

# ESA Inspections:

Report No. S20418850-N59-001

Electrical Safety Authority

Phone: 1-877-854-0079
Fax: 905-712-7886
CSS.ContactUs@electricalsafety.on.ca

155 Matheson Blvd. West
Mississauga, Ontario, L5R 3L5

**Continuous Safety Services**
**Site Visit Report**

The electrical systems of the [illegible] that inspection are identified on this report. In addition, you will also find an Outstanding Defect Report attached that outlines electrical defects that are still in our records as uncorrected. Please advise Derek Hertz once you have corrected any defects that were found.

| Customer Information | Site Information |
|---|---|
| HYDRO ONE REMOTE COMMUNITIES INC<br>680 BEAVERHALL PL<br>THUNDER BAY, ON<br>Attn: KRAEMER COULTER | SACHIGO GS AND HOUSE<br>FLY IN COMMUNITY<br>SACHIGO, ON<br>Attn: CLARK LEMAY |

**Issue Date:** 2016/09/16
**Purpose of Visit:** Inspection
**Visit Contact:**

**Inspector Name:** Derek Hertz
**Inspector Cell #:** 807-620-9346
**Inspector Email:** DEREK.HERTZ@ELECTRICALSAFETY.ON.CA

**Recommendations**

| | Risk Factor | | | Initial if corrected |
|---|---|---|---|---|
| 1 | N/A | Notification #: 20418850 Issue Date: 2016-09-16<br>Rule Reference: 82-004(a) No defects<br>Defect Location: | Defect Status: Completed<br>Defect #: 2 | |
| | | Code Rule: No defects were identified.<br>Inspector Comments: | | |

**Thank you for giving us the opportunity to help you improve the safety of your facility. Your attention to these hazards, defects and recommendations will ensure continued safety on your premises. Should you have any questions regarding the items listed in this report, please do not hesitate to contact us.**

# Reg 22/04 Audits:

| | |
|---|---|
| 20 | 8" |
| 60 | 2'-0" |
| 150 | 5'-0" |

**PARTS LIST**

| PART No: | MM No: | DESCRIPTION | QUANTITY FIG.1 | QUANTITY FIG.2 |
|---|---|---|---|---|
| 1 | MM# | CONNECTOR, TAP, WEDGE | 4 | 2 |
| 2 | 30014480 | CONDUCTOR, BARE COPPER #4 | A/R | A/R |
| 3 | MM# | CONNECTOR, STIRRUP | 1 | 2 |
| 4 | 30006195 | CONNECTOR, LIVE LINE | 3 | 3 |
| 5 | MM# | INSULATOR, STANDOFF | 3 | 1 |
| 6 | 30000770 | CLAMP, REST | 2 | 1 |
| MM# – REFER TO SECTION 16 ONLY | | A/R – AS REQUIRED | | |

NOTES:
1. FOR TRANSFORMER INSTALLATION AND PARTS LIST SEE DL9-103.
2. FOR SINGLE PHASE INSTALL REMOVE FIELD & ROAD SIDE TRANSFORMERS & CONNECT TO DESIRED PHASE.
3. SEE DL9-107.1 FOR APPLICABLE FRAMINGS.

REFERENCES:
SECTION 3 – FRAMING
SECTION 4 – POLES
SECTION 5 – ANCHORING AND GUYING
SECTION 6 – VOLTAGES, LINE LOCATIONS AND CLEARANCES
SECTION 7 – CONDUCTORS AND CONNECTORS
SECTION 8 – OVERCURRENT PROTECTION AND SWITCHING
SECTION 10 – REGULATORS AND CAPACITORS
SECTION 11 – SERVICES & METERING
SECTION 12 – GROUNDING
SECTION 16 – MATERIALS LIST
COMPATIBLE UNITS MANUAL

ALL DIMENSIONS ARE IN CENTIMETRES UNLESS STATED OTHERWISE

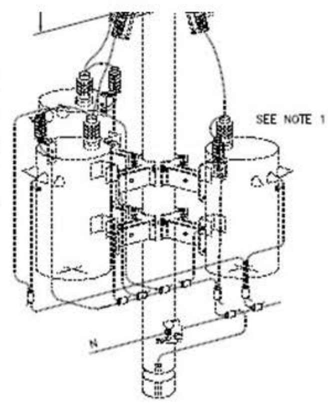



FIG.1
TRANSFORMER INSTALLATION ON DOUBLE CIRCUIT

| Rev. No. | Issue Date | Revision | Dsn / Chk | Approved By / Date |
|---|---|---|---|---|
| 04 | OCT 2014 | REVD PARTS LIST. REFORMATTED DWG TO CAD STDS. | LS / PC | * |
| 03 | DEC 2012 | ADDED MM#, MIN. DIM. AND GENERAL REVISION | GJ / PC | * |



Hydro One Networks Inc.

| Drawn: | Approved: | Date: |
|---|---|---|
| MV | * | MAR. 26.2009 |

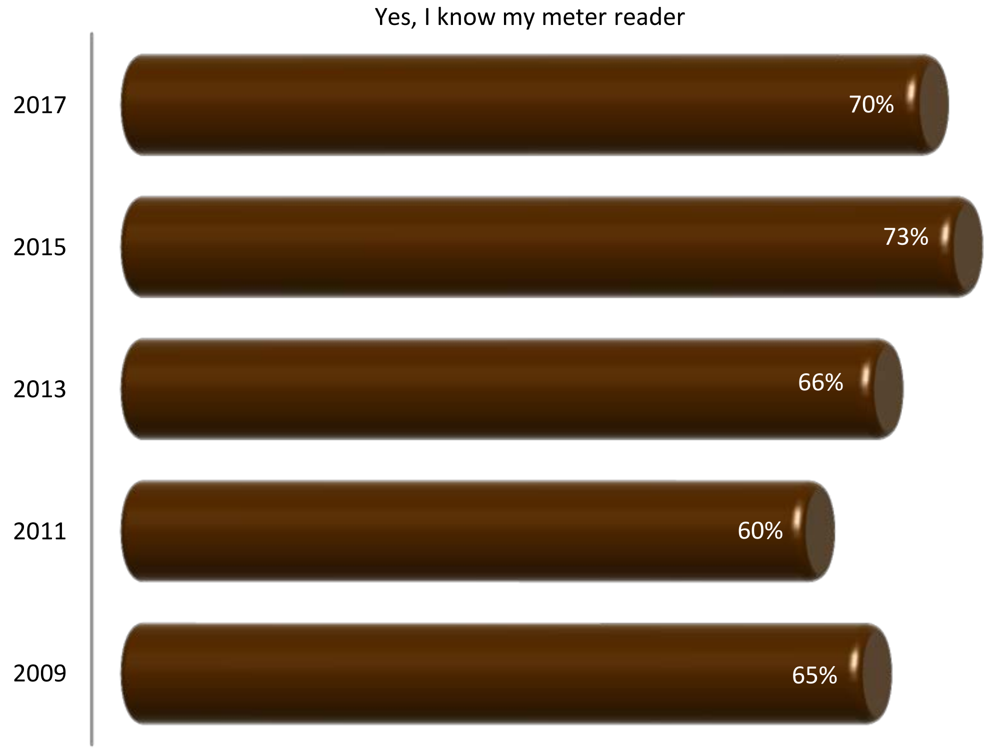
TRANSFORMER INSTALLATION, MULTI-CIRCUIT POLES 30kVA TO 501kVA, 3Ø, 2.4/4.16kV TO 16/27.6kV

Dwg. No. DL9-105 Rev. 04

### *Awareness of Meter Readers (Q14)*

Seven in ten respondents know who their meter reader is (70%), down 3 points from 2015 and at its second highest level over five waves of tracking. One in three customers admitted they do not know their local meter reader (30%), up 3 points.

Chart 12: **Awareness of Hydro Meter Readers**

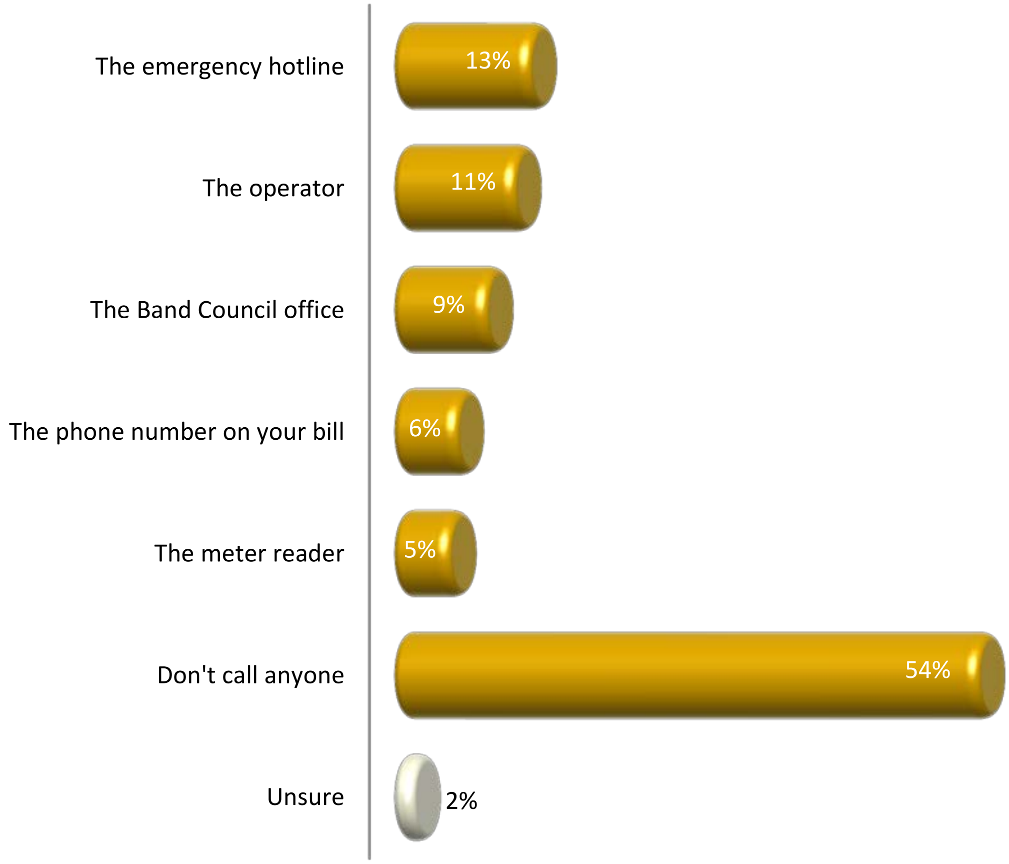



- Among communities with 10 or more respondents, Sultan (100%) and Big Trout Lake/KI (90%) are most likely to know their meter reader, and Armstrong/Whitesands/Collins is least likely to (33%).

### *Contact During Outages (Q15)*

A majority of customers do not call anyone when there is an outage (54%). One in eight call the emergency hotline (13%), while fewer call the operator (11%) or the Band Council Office (9%). Six percent (6%) call the phone number on their bill and 5% call the meter reader. Two percent (2%) are unsure.

Chart 13: **Contact During Outages**

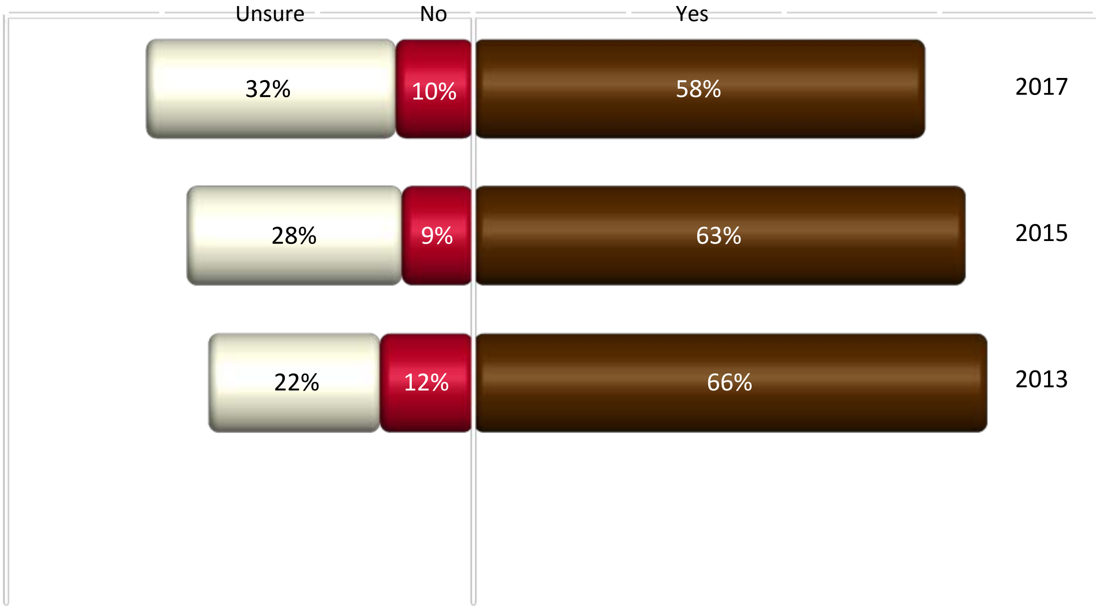



## Hydro One Remotes & the Environment

### *Local Environmental Protection* *(Q17)*

About six in ten Hydro One Remotes customers said the utility takes environmental protection in the community seriously (58%), down 5 points since 2015 and 8 points since 2013. About one in ten said Hydro One does not take it seriously (10%), similar to the last two waves of research. One third of respondents were unsure (32%), up 4 points.

Chart 14: **Does Hydro Take Local Environmental Protection Seriously?**

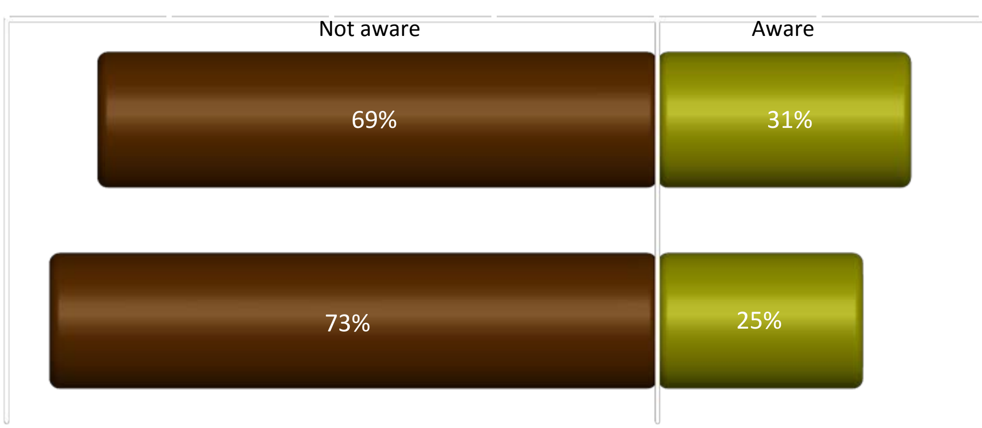



- In communities with 10 or more respondents, Biscotasing (90%), Deer Lake and Sultan (each 73%) are most likely to say Hydro takes this seriously, and Big Trout Lake/KI is least likely to (10%).

### ***Renewable Electricity Generation*** *(Q21)*

About three in ten customers were aware communities like theirs can generate renewable electricity through solar, wind or small hydro water projects and sell it back to Hydro One Remotes (31%, up 6 points since 2015), while 69% were not aware of this potential or were unsure.

Chart 15: **Renewable Electricity Generation**

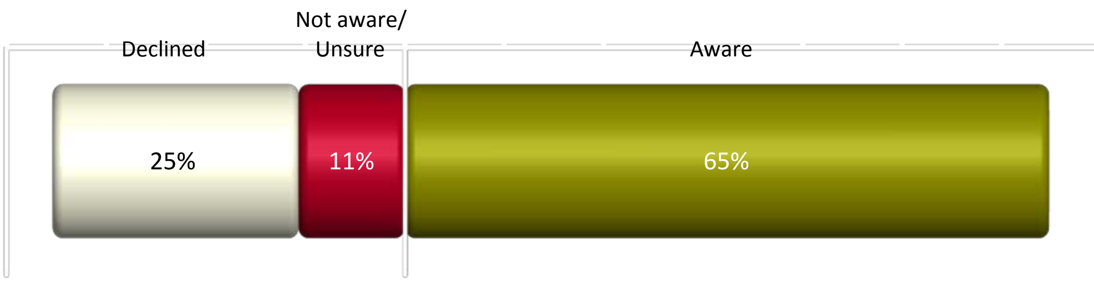


- Men are much more likely to be aware that their communities can generate electricity and sell it back to Hydro (43%) than women (16%).

### *Investment in Renewable Energy (Q22)*

Two thirds of customers hold the view that Hydro should invest more in renewable energy (65%), while 11% said no or were unsure and 25% declined to answer the question.

Chart 16: **Investment in Renewable Energy**




- Men are also more likely than women to think Hydro should invest more in renewable energy (70% vs. 58%).

## Electricity Rebates & Programs

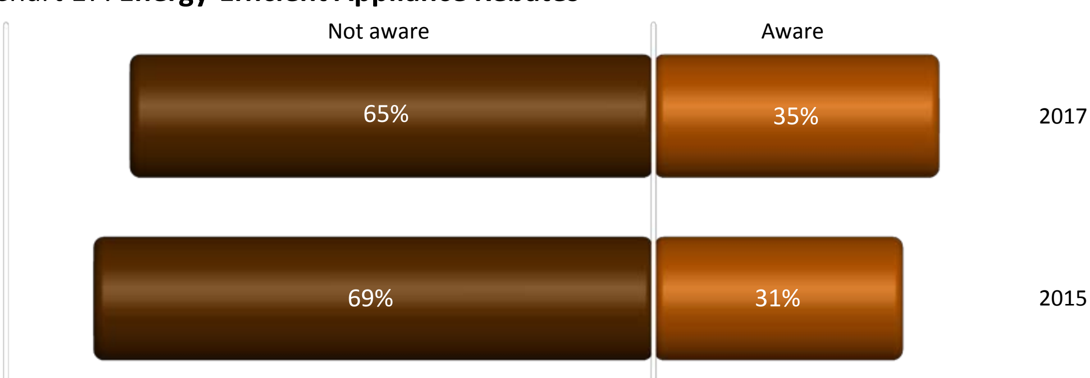
A minority of Hydro One Remotes customers is aware of various electricity-related rebates and programs available to them.

### *Appliance Rebates (Q18)*

More than one third of customers are aware they can receive rebates up to $200 when they buy energy-efficient appliances (35%), up 4 points since 2015.

- The likelihood of being aware of this rebate increases with age, from 10% of 18 to 34-year-olds to 46% of those 55+.

Chart 17: **Energy-Efficient Appliance Rebates**



### ***LEAP & OESP*** *(Q19 & Q20)*

Awareness has jumped regarding the Low-Income Emergency Assistance Program (LEAP) (33%, up 15 points), while one in four is aware of the Ontario Electricity Support Program (OESP) (25%).

- In communities with 10 or more respondents, Sachigo Lake (75%) and Sultan (55%) are most likely to know about LEAP, while Big Trout Lake/KI (10%) and Deer Lake (18%) are least likely to.
- Customers who contacted Hydro in the past year are more than twice as likely to know about LEAP (45%) than those who did not contact Hydro (21%).

Chart 18: **LEAP Program**

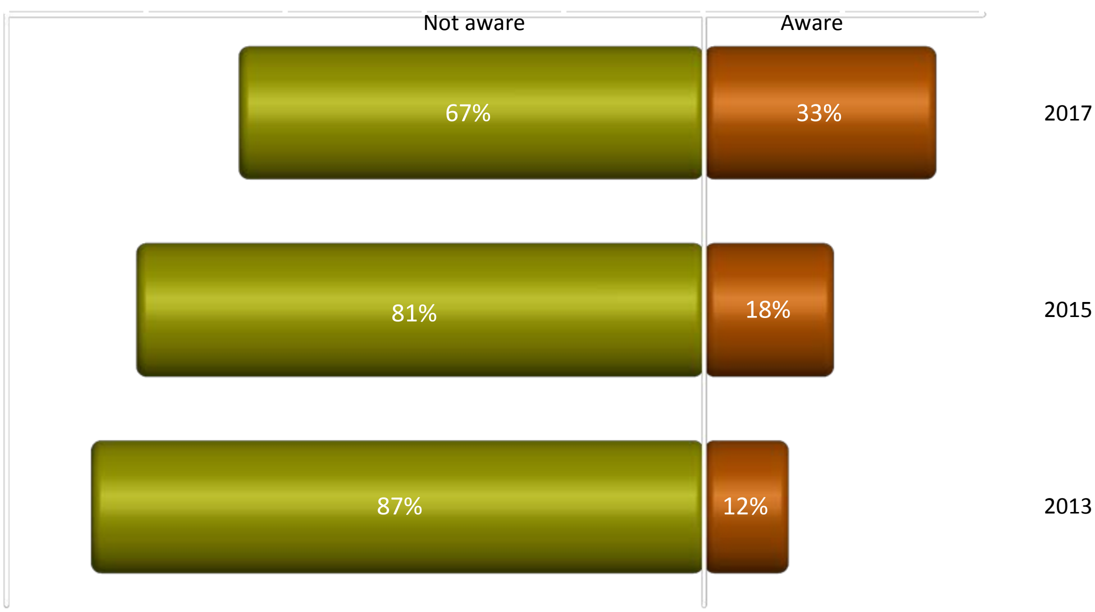
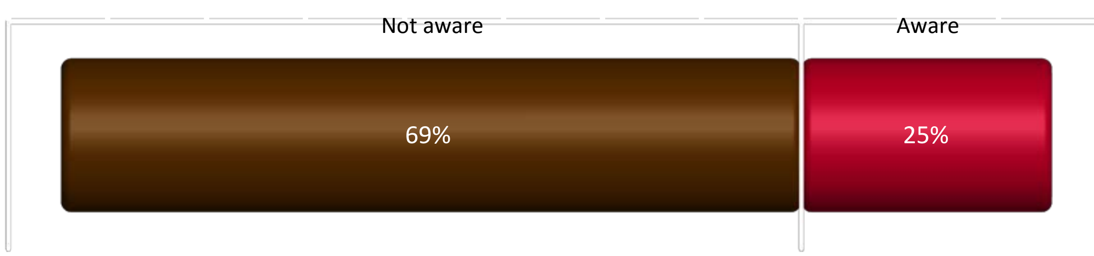



Chart 19: **OESP Program**



# PERFORMANCE MANAGEMENT

"We supply safe, reliable and affordable electricity to remote communities by focusing on continuous improvement, operational excellence and outstanding customer service."

## 1.0 INTRODUCTION

The Board has established specific measures and four key areas of performance for Electrical Distribution Utilities. The key performance areas are:

- Customer focus;
- Operational effectiveness;
- Public policy and responsiveness; and
- Financial performance.

Remotes manages its business based on the principles of continuous improvement established under the ISO framework, taking a disciplined approach to continuous improvement in all aspects of its operations. Based on its business model and mission, priority areas of concern are safety, reliable and affordable electricity, operational excellence and customer service. Objectives that Remotes believes align well with the Board's key performance areas. To measure and monitor its performance, Remotes sets annual targets and plans for improvement in the areas of financial strength, customer relations, operational excellence, productivity, environmental stewardship and health and safety. The progress made in achieving these targets is monitored through an internal scorecard. Copies of the internal scorecards from 2013 to July 2017 can be found as Attachment 1 of this exhibit. The Remotes' Electricity Scorecard can found as Attachment 2.

## 2.0 CUSTOMER RELATIONSHIPS

Annually, Remotes establishes targets to improve its customer relationships and overall customer service. Since 2011, Remotes has established targets and tracked the number of Band Council meetings its Director has with First Nation Band Councils and Tribal Councils. Remotes conducts a biennial random sample customer survey, and in those years also establishes a target of 90% satisfaction, based on previous survey results. In order to improve performance on specific areas of customer service, Remotes will, from time to time, increase the profile of various transactional customer service measures. Over the five year period, those areas included meeting the Ontario Energy Board Reconnection Standard and answering telephone calls within thirty seconds. In 2016, Remotes decided to begin tracking a range of customer initiatives in a way similar to the ISO framework, where Remotes staff and management thought improvements of the customer experience could be made. Since 2016 is the first year for this metric, no year over year comparisons are available. Activities under this initiative included activities to improve bill accuracy, customer awareness of the LEAP and OESP programs, public safety activities, improvements to various customer letters and other customer communications.

<u>Band/Tribal Council Meetings</u>

Previous customer surveys indicated that community members and in particular community leaders like to know people in the company personally. Being able to put a face to a name builds trust on both sides. To ensure that community leaders and the Director know one another, Remotes decided, starting in 2011, to track the number of Band Council and Tribal Council that the Director attends. The target for this initiative is to meet with the Band or Tribal Council at least eight times per year. Here are the actuals achieved for 2013 to July 2017 inclusive:

- 2013 – actual achieved 8 meetings;
- 2014 - actual achieved 9 meetings;
- 2015 - actual achieved 8 meetings;
- 2016 - actual achieved 13 meetings; and
- July 2017 - actual achieved 17 meetings with the Director's First Nation/Tribal Council meetings.

As this metric is an important aspect of building relationships with communities, Remotes will continue to track this metric.

## 3.0 ENVIRONMENTAL STEWARDSHIP

The following are metrics on the Remotes' internal scorecard regarding environmental stewardship.

<u>Environmental Containment</u>

Remotes' customers and the provincial and federal governments are all concerned about the environment. Because Remotes uses diesel fuel it establishes various metrics to drive improvements to fuel handling, spill reporting and compliance with fuel regulations. Since 2001 Remotes has tracked fuel spills, starting with a target of less than or equal to 300 litres per year lost to the environment. The target is now less than or equal to 100 litres per year. This new target was achieved in each of the last five years with the total spills being zero in four of those years. The achieved results are as follows:

- 2013 – actual achieved 0 litres spilled;
- 2014 – actual achieved 10 litres - Two small spills in garages in Sandy Lake and Deer Lake went directly into the ground. Although both spills were cleaned-up, small amounts of containment were lost to the environment.

- 2015 - actual achieved 0 litres spilled;
- 2016 - actual achieved 0 litres spilled; and
- July 2017 - actual achieved 0 litres spilled.

<u>Environmental Management System ("EMS") Objectives and Achievements</u>

Each year, the Remotes Steering Committee ("RSC") establishes objectives and achievements to base the ISO model (plan, do, check, act), which is designed to drive continuous improvement in a company's environmental objectives. The current key environmental objectives are preventing pollution, reducing noise emissions and reducing air emissions. Programs are developed annually to meet these objectives. The target for acceptable performance is the completion of 80% of planned deliverables. Results for the last three and half years are illustrated in Figure 1 below.

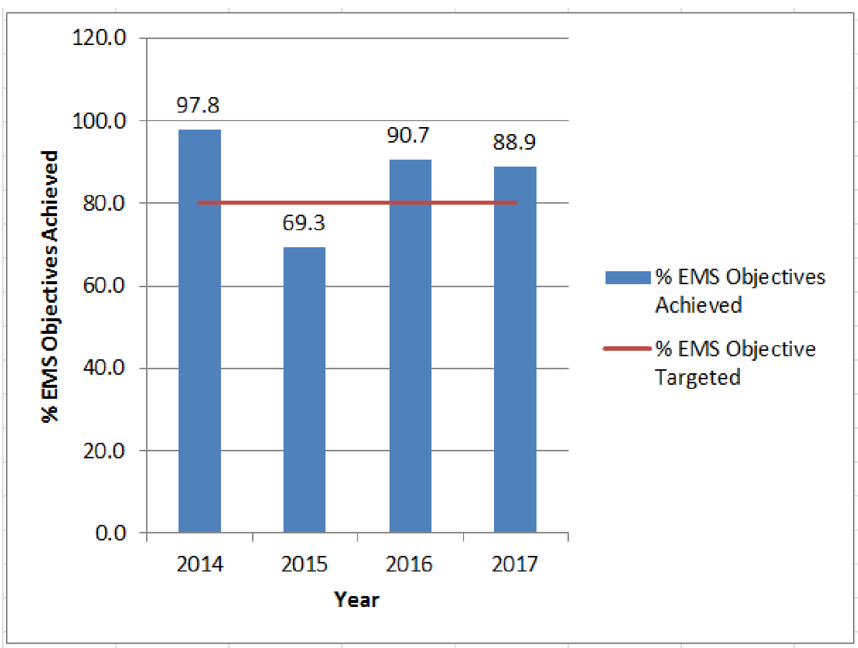



**Figure 1 - Achievement of Environmental Management System Objectives**

*2017 result only covers to the end of July

In 2015, some targets that required First Nations' involvement were not completed as communities focused on other priorities, resulting in a lesser performance than targeted.

## 4.0 FINANCIAL STRENGTH

Each year, depending on business priorities and results from previous years, Remotes establishes specific annual targets to improve its financial performance. Due to Remotes' break-even business model, targets such as net income or financial ratios are not appropriate measures of performance. Consequently, Remotes establishes annual priorities that reduce its costs or improve the efficiency of its operations under this performance bucket.

Reducing Residential Arrears

For the past decade, Remotes has focused on ways to reduce overall customer arrears and, in particular, ways to improve residential bill collection while continuing to maintain high levels of customer satisfaction and positive relationships with its First Nation communities. For the purposes of the internal report card, Remotes tracked this metric in three of the past five years 2014, 2015 and 2016 with a target to reduce arrears by 5% in each of those years. Historical year achievements include:

- 2014 – actual achieved a 6% reduction;
- 2015 – actual achieved a 23% reduction; and
- 2016 – actual achieved a 5% reduced despite $1.64 million in higher billings due to the removal of the Ontario Clean Energy Benefit.

Although the scorecard only shows residential arrears, Remotes focuses on reducing outstanding balances for all customer classes, as it improves Remotes financial performance, is less costly for its direct customers and less costly for the customers who fund RRRP. Since 2006, Remotes has reduced outstanding accounts receivable for all classes of customers by 82%, as shown in Figure 2.

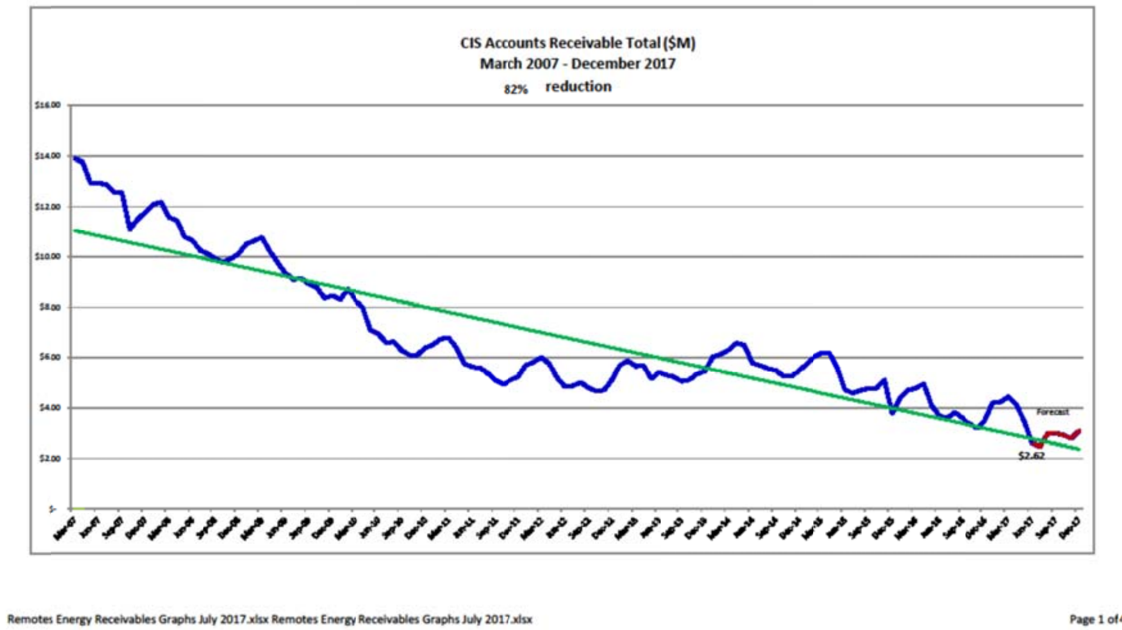



**Figure 2 - CIS Accounts Receivable**

In 2013, customer collections activity was reduced as a result of the implementation of a new billing system. In that year, Remotes chose targets expected to reduce its overall operating costs. Targets included negotiating a new agreement with Deer Lake First Nation related to the Shoulderblade Falls hydroelectric station as the station provides financial benefits to Remotes and to the First Nation. That year, Remotes also focused on winter road planning milestones to ensure that fuel and equipment would be transported in the most cost effective way to the communities. In 2015, Indigenous and Northern Affairs Canada ("INAC") agreed to fund three large generation capital projects. To ensure maximum benefit to both ratepayers and INAC, Remotes decided to also track the project delivery times and budgets as a financial measure. In 2017, Remotes decided to track milestones related to the preparation of its first Distribution System Plan and its preparation of the cost of service filing as its financial measures.

## 5.0 HEALTH AND SAFETY

The following are Health and Safety metrics that Remotes tracks and monitors.

<u>Mandatory Training</u>

Remotes understands the importance of creating a culture focused on the health and safety of all employees and the public. To create this culture, Remotes chose to measure the level of completion of all Health and Safety mandatory training. The results are shown in Figure 3.

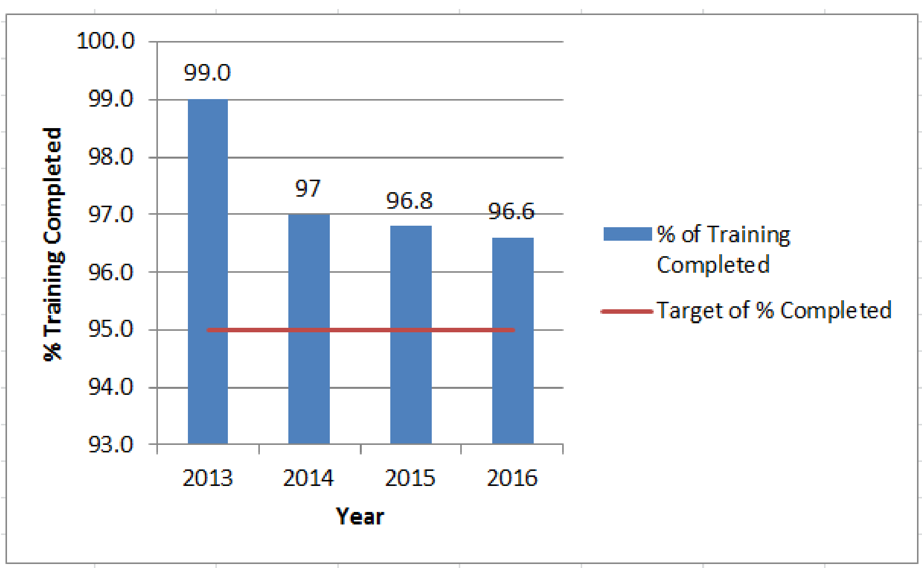



**Figure 3 - Completion of Mandatory Training**

As Remotes met this metric consistently, it was dropped at year end in 2016 to focus its internal reporting on other areas requiring improvement.

Lost Time Injuries

From 2013 to July 2017, the Remotes have had zero lost time injuries.

Health and Safety Management System (“HSMS”) Objectives and Achievements

Each year, the RSC establishes objectives and achievements to control safety risks and improve health and safety performance based on the ISO model, which is designed to drive continuous improvement. As part of this process, the RSC develops a number of deliverables that improve safety performance. Many of these improvements, such as snow clearing, improved walkways on site and ensuring that required equipment is on site also have efficiency benefits. The target for acceptable performance is the completion of 80% of planned deliverables. The results are shown in Figure 4.

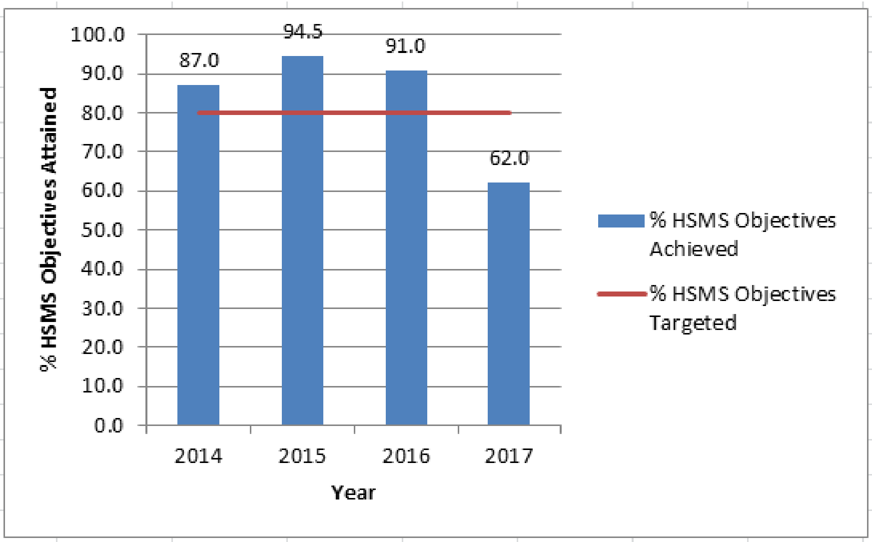



**Figure 4 - Achievement of Health and Safety Management System Objectives**

*2017 result only covers to the end of July

## 6.0 OPERATIONAL EXCELLENCE

Remotes sets annual targets for its reliability performance, using the Board reliability measures and also by establishing a measure for generation availability. In terms of the Board measures, Remotes aims to meet or improve on its five year average for System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") including loss of supply. For the purposes of internal reporting, Remotes excludes events that meet its own definition of major events. Remotes internal standard excludes outages beyond Remotes' control, that result in widespread system damage affecting an entire community; or an outage that affects an entire community for duration of at least twelve hours because staff cannot access the community due to circumstances beyond the control of the company (i.e. as a result of adverse weather that prevents a plane from landing). This does not meet the test of the IEEE standard required by the Board. SAIDI performance in 2016 and 2017 reflects adjustments for major events.

The measure for generation availability is based on the minutes of station outages. For internal purposes, this is different from the calculation in the Distribution System Plan (Exhibit B, Schedule 1, Section 2.3) as the internal goal established was to assume that the generation is a single system, rather than nineteen separate generating stations. Major events as described above and planned generation outages related to capacity upgrades are excluded from this internal performance measurement.

<u>SAIDI and SAIDI Results</u>

The Remotes' SAIDI and SAIFI results using the metric on the internal scorecard are illustrated in Figures 5 and 6.

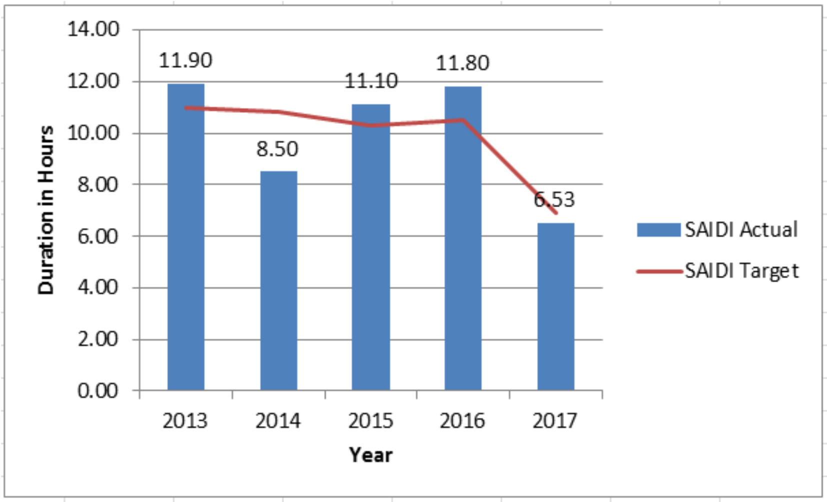



**Figure 5 - Remotes' SAIDI Performance**

*2017 result only covers to the end of July

In 2013, the SAIDI target was missed by 8.4%, mainly related to unplanned engine failures and defective equipment, including an outage in Wapekeka related to a faulty main breaker, a generation trip in Kasabonika Lake and problems with the Programmable Logic Controller ("PLC") in Sachigo Lake. In 2015, an increase in planned outages related to generation upgrades and distribution system improvements, resulted in customer disruptions that were longer than the historical trend. In 2016, the duration of outages was longer than in 2014 and 2015 due to increased planned outages that were required for distribution system improvements. Planned distribution outages accounted for 35% of SAIDI. The 2017 result excludes two major storm events in March and April.

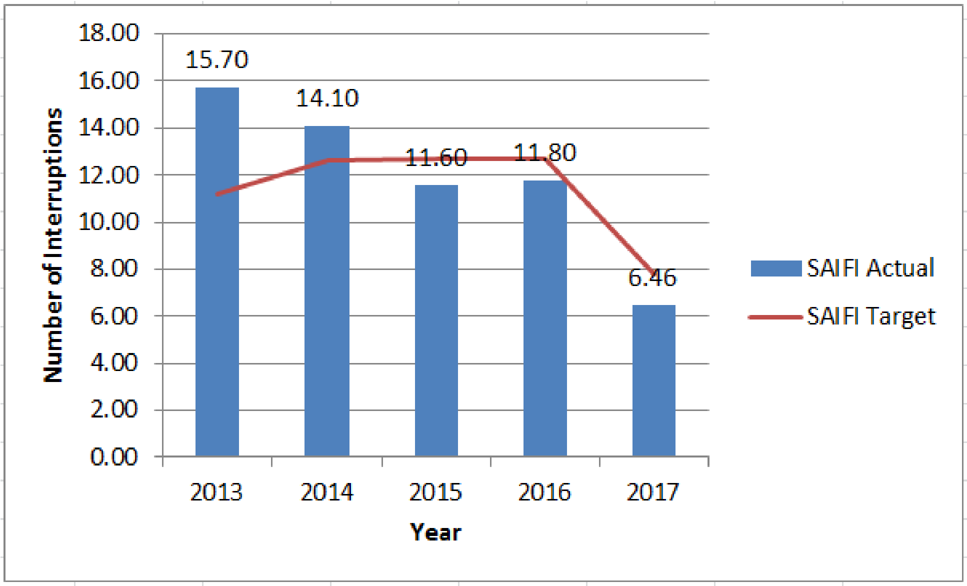



**Figure 6 - Remotes' SAIFI Performance**

*2017 result only covers to the end of July

In 2013, Remotes exceeded the SAIFI year-end frequency performance target by 40%, due to problems with the C unit in Marten Falls, under voltage engine trips in Big Trout Lake and various plant and engine problems in Weagamow. In 2014, SAIFI was slightly under the average performance due to PLC issues in Sandy Lake.

<u>Generation Availability</u>

This internal metric is measured differently from the one discussed in the Distribution System Plan as it assumes all outages occur at one station. The results attained for this metric are shown in Figure 7 below.

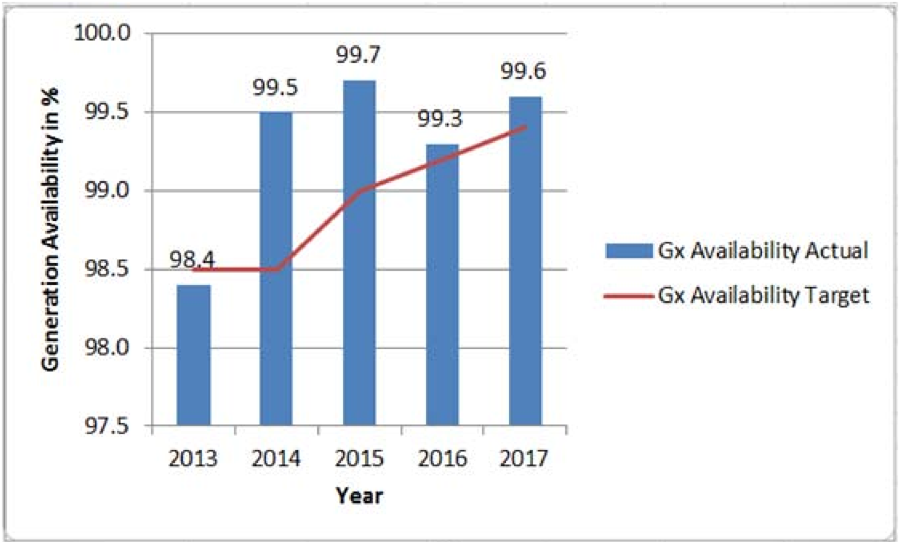



**Figure 7 - Percentage of Generation Availability**

*2017 result only covers to the end of July

In 2013, wiring and control problems with the largest unit in Kasabonika Lake caused the community to lose power. Cold weather and difficulties with cold load pickup meant the local operator was unable to restore power with the remaining capacity. Due to plane availability and the timing of the outage, crews were not able to get to site until the next morning to restore power. To avoid further problems with cold load pickup, Remotes is making multi-year investments to install viper switches in its distribution systems.

## 7.0 EFFICIENCY OF OPERATIONS

The inaccessibility of Remotes' service territory makes it difficult to establish metrics for productivity and efficiency improvements. The cost to transport staff and equipment can mask efficiency improvements on site. As part of its business planning process in 2012, Remotes determined that improvements to its management of projects would likely yield the best results in terms of efficiency improvements, because careful planning of equipment purchases, staff time on site and project staging are all required to ensure that transportation costs are kept to budget. As each capital project has unique characteristics it is hard to directly compare them. Instead Remotes identifies the milestones of one major project a year and sets the timelines and budget for the project accordingly. Remotes then monitors how well the project stays on track according to these milestones and documents any deficiencies. This process also aids in identifying any areas, efficiency can be introduced and realized in subsequent projects. Table 1 below identifies the projects tracked for this metric.

**Table 1**

**Major Project Milestones**

| Year | Project | Achieved Milestones | Target Milestones |
|---|---|---|---|
| 2013 | Sandy Lake Engine Project On Time | 17 | 17 |
| 2014 | Lansdowne House Engine Replacement | 8 | 9 |
| 2015 | Wapekeka Engine Replacement Project Milestones | 16 | 16 |
| 2016 | Bearskin Engine Replacement Project Milestones (on time, on budget) | 14 | 14 |
| 2017 | Kingfisher Upgrade Milestones (on time, on budget) | 7 | 7 |

In 2014, increased electrical work related to the engine replacement in Lansdowne House delayed the post-commissioning/deficiency meeting, the final milestone for this metric. In 2016, The Bearskin Engine project was under budget and therefore better than planned.

<u>Fuel Efficiencies</u>

The cost and delivery of fuel is Remotes single largest cost. To increase efficiency and lower costs, Remotes has:

- Issued competitive bid contracts through the tendering process for fuel and delivery;
- Maximized cheaper winter road deliveries through supplier relationships and improved management of existing storage;
- Entered in to contracts with First Nations who own storage tanks to increase the supply of winter road fuel;
- Offered customers conservation opportunities; and
- Invested in more fuel efficient engines.

Fuel initiatives are discussed further in Exhibit D1, Tab 1, Schedule 2.

# HYDRO ONE REMOTE COMMUNITIES INC.

**DECEMBER 2013**

## SCORECARD

| Strategic Objective | | Performance Measure | Actual | Year End | |
|---|---|---|---|---|---|
| | | | Actual | Target | Result |
| Financial | Financial Strength | Negotiate Shoulderblade Falls Agreement & Restore Operating Condition | 8 | 6 | ★ |
| | | 2013 Winter Road Planning Milestones | 6 | 5 | ★ |
| Innovation | Environmental Stewardship | Litres lost to the environment | 0 | ≤100 | ● |
| | | Number of Category A spills | 0 | 0 | ● |
| Customer | Inspire Customer Loyalty and Improve Customer Relationships | Customer Satisfaction Survey | 98% | ≥90% | ★ |
| | | Band Council Meetings | 8 | 8 | ● |
| Business Excellence | Maintain/Improve System Reliability | System Duration of Total Interruptions (SAIDI) Hours interruption per delivery point[1] | 11.9 | 11.0 | ▲ |
| | | System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point[2] | 15.7 | 11.2 | ▲ |
| | | Percentage of Generation Availability[3] | 98.4% | 98.5% | ● |
| | Improve Compliance | Weagamow Tank Farm Replacement | 6 | 6 | ● |
| | | Improve site conditons | 7 | 7 | ● |
| Productivity | Improve efficiency of operations | Sandy Lake Engine Project On Time | 17 | 17 | ● |
| | | EMS Objectives and Achievements | $1.6M | $1.8M | ★ |
| Organizational Strength | Injury Free Workplace | Lost Time Injury | 0 | 0 | ● |
| | | Medical Attention Injury[4] | 3 | ≤2 | ▲ |
| | | Completion of mandatory training | 99% | 95% | ★ |
| | Workforce Engagement | Employee Engagement Survey Results | N/A | 3.66 | N/A |
| **Legend** | | ★ Better than plan | ● On plan | ▲ Worse than plan | |

[1] Year-end duration performance is 11.9 hours, which exceeds the target of 11.0 by 8.4%, mainly related to planned distribution outages that will improve future reliability.
[2] Year-end frequency performance is 15.7, which exceeds the target of 11.2 by 40%. Our larger communities experienced a higher than normal number of bird strikes and voltage-related generation outages during the summer months.
[3] Wiring and control problems with the largest unit in Kasabonika Lake caused the community to lose power. Brutally cold weather and difficulties with cold load pickup meant we were unable to restore power with the remaining capacity. Due to plane availability and the timing of the outage, crews were not able to get to site until the next morning to restore power.
[4] Unfortunately employees experienced two exertion injuries and one slip trip and fall that required medical attention.

## SCORECARD

| Strategic Objective | | Performance Measure | Actual | Year End | |
|---|---|---|---|---|---|
| | | | Actual | Target | Result |
| Business Excellence | Financial Strength | Reduce Residential Arrears by 5% | -6% | -5% | ★ |
| Customer Relations | Inspire Customer Loyalty and Improve Community Relationships | Band/Tribal Council Meetings | 9 | 8 | ★ |
| | | Meet OEB Reconnection Standard | 100% | ≥85% | ★ |
| Operational Excellence | Maintain/Improve System Reliability | System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point | 8.5 | 10.8 | ★ |
| | | System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point[1] | 14.1 | 12.6 | ▲ |
| | | Percentage of Generation Availability | 99.5% | 98.5% | ★ |
| Productivity | Improve Efficiency of Operations | Bearskin Engine Replacement Project Milestones (on time, on budget)[2] | 8 | 9 | ▲ |
| Environmental | Environmental Protection | Litres lost to the Environment | 10 | ≤100 | ★ |
| | | Category A Spills | 0 | 0 | ● |
| | | Spills outside of containment | 2 | ≤4 | ★ |
| | Continuous Improvement | EMS Objectives and Achievements | 44 | 36 | ★ |
| Health & Safety | Injury Free Workplace | Lost Time Injury | 0 | 0 | ● |
| | | Total Recordable Injury | 0 | ≤2 | ★ |
| | | Completion of Health & Safety Training | 96.6% | 95% | ★ |
| | Continuous Improvement | HSMS Objectives and Achievements | 33 | 29 | ★ |
| **Legend** | | ★ Better than plan | ● On plan | ▲ Worse than plan | |

[1] SAIFI was worse than plan due to short-term generation and distribution outages mainly related to PLC issues with generation switching and controls, and a higher than usual number of bird strikes in our largest community.
[2] The Bearskin Engine project was under budget and therefore better than plan.

## SCORECARD

| | Strategic Objective | Performance Measure | Actual | Year End Target | Year End Result |
|---|---|---|---|---|---|
| Business Excellence | Financial Strength | Reduce Residential Arrears by 5% | -23% | -5% | ★ |
| | Maximize Net Benefit | Recoverable generation projects on-time and on-budget[1] | $6.6M | $6.9M | ★ |
| Customer Relations | Inspire Customer Loyalty and Improve Community Relationships | Band/Tribal Council Meetings | 8 | 8 | ● |
| | | Telephone Answered within 30 seconds | 91.4% | ≥90% | ★ |
| Operational Excellence | Maintain/Improve System Reliability | System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point[2] | 11.1 | 10.3 | ▲ |
| | | System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point | 11.6 | 12.7 | ★ |
| | | Percentage of Generation Availability | 99.7% | 99% | ★ |
| Productivity | Improve Efficiency of Operations | Wapekeka Engine Replacement Project Milestones | 16 | 16 | ★ |
| Environmental Stewardship | Environmental Protection | Litres lost to the Environment | 0 | ≤100 | ● |
| | | Category A Spills | 0 | 0 | ● |
| | | Spills outside of containment | 0 | ≤1 | ★ |
| | Continuous Improvement | EMP Initiatives[3] | 26 | 30 | ▲ |
| Health & Safety | Injury Free Workplace | Lost Time Injury | 0 | 0 | ● |
| | | Total Recordable Injury | 1 | ≤2 | ★ |
| | | Completion of Mandatory Training | 96.8% | 95% | ★ |
| | Continuous Improvement | HSMP Initiatives | 65 | 55 | ★ |
| Legend | | ★ Better than plan | ● On plan | ▲ Worse than plan | |

[1] The three generation projects are now all in service. The Fort Severn project was slightly over budget due to freight costs; Deer Lake and Wapekeka were both under budget. INAC and Wapekeka First Nation agreed to allow Remotes to recover costs associated with Phase 1 of the Wapekeka and Big Trout Lake Tie Line and the former Big Trout Lake DGS upgrade, thereby reducing Remotes' non-energy receivables.

[2] Due to an increase in planned outages related to generation upgrades and distribution system improvements, customer disruptions are longer than the historical trend.

[3] Several targets that require First Nation involvement were not completed as communities focused on other priorities.

## SCORECARD

| Strategic Objective | | Performance Measure | Actual | Year End | |
|---|---|---|---|---|---|
| | | | Actual | Target | Result |
| Business Excellence | Financial Strength | 5% Reduction in Total Energy Arrears[1] | $3.3M | -5% $3.42M | ★ |
| Customer Relations | Inspire Customer Loyalty and Improve Community Relationships | Band/Tribal Council Meetings | 13 | 8 | ★ |
| | | Telephone Answered within 30 seconds | 100% | 95% | ★ |
| Operational Excellence | Maintain/Improve System Reliability[2] | System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point | 11.8 | 10.5 | ▲ |
| | | System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point | 11.8 | 12.7 | ★ |
| | | Percentage of Generation Availability | 99.3% | 99.2% | ● |
| Productivity | Improve Efficiency of Operations | Bearskin Engine Replacement Project Milestones (on time, on budget)[3] | 14 | 14 | ★ |
| Environmental Stewardship | Environmental Protection | Litres lost to the Environment | 0 | ≤100 | ★ |
| | | Category A Spills | 0 | 0 | ● |
| | | Spills outside of containment | 0 | ≤4 | ★ |
| | | EMS Objectives and Achievements | 17 | 15 | ★ |
| Health & Safety | Injury Free Workplace | Lost Time Injury | 0 | 0 | ● |
| | | Total Recordable Injury | 0 | ≤2 | ★ |
| | | Completion of Health & Safety Training | 96.6% | 95% | ★ |
| | | HSMS Objectives and Achievements | 33 | 29 | ★ |
| **Legend** | | ★ Better than plan | ● On plan | ▲ Worse than plan | |

[1] We are successfully managed customer arrears to lower levels than last year despite $1.64M in higher billings due to the removal of the Ontario Clean Energy Benefit.
[2] SAIDI is lower than prior years due to increased planned distribution outages that were required due to distribution system improvements. Planned distribution outages account for 35% of SAIDI.
[3] The Bearskin Engine project was under budget and therefore better than plan.

## SCORECARD

| Strategic Objective | | Performance Measure | Year to Date | | Status | Year End | |
|---|---|---|---|---|---|---|---|
| | | | Actual | Target | YTD | Target | Projected |
| Business Excellence | Financial Strength | Distribution System Plan & Cost of Service Filing Milestones | 20 | 20 | ● | 23 | ● |
| Customer Relations | Inspire Customer Loyalty and Improve Community Relationships | Customer Satisfaction Survey Results | 90% | ≥ 90% | ● | ≥ 90% | ● |
| | | Director's FN/Tribal Council Meetings | 17 | 4 | ★ | 8 | ★ |
| | | Customer & Community Outreach Initiatives[1] | 9 | 8 | ★ | 21 | ● |
| Operational Excellence | Maintain/Improve System Reliability | System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point[2] | 6.53 | 6.92 | ★ | 11.24 | ● |
| | | System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point | 6.46 | 7.82 | ★ | 12.97 | ● |
| | | Generation Availability | 99.6% | 99.4% | ★ | 99.4% | ● |
| Productivity | Improve Efficiency of Operations | Kingfisher Upgrade Milestones (on time, on budget) | 7 | 7 | ● | 13 | ● |
| Environmental Stewardship | Environmental Protection | Litres lost to the Environment | 0 | ≤100 | ● | ≤100 | ● |
| | | Hydro One Spills | 3 | ≤3 | ● | 6 | ● |
| | | Category A Spills | 0 | 0 | ● | 0 | ● |
| | | EMS Objectives and Achievements[1] | 20 | 18 | ★ | 34 | ● |
| Health & Safety | Injury Free Workplace | Lost Time Injury | 0 | 0 | ● | 0 | ● |
| | | Total Recordable Injury | 1 | ≤2 | ● | ≤2 | ● |
| | | High MRPH Incidents | 0 | ≤1 | ● | ≤1 | ● |
| | | HSMS Objectives and Achievements[1] | 7 | 9 | ▲ | 25 | ● |
| Legend | | ★ Better than plan | ● On plan | | ▲ Worse than plan | | |

[1] Reported quarterly

[2] Excludes two major storm events in March and April.

# Scorecard - Hydro One Remote Communities Inc.

9/29/2016

| Performance Outcomes | Performance Categories | Measures | | 2011 | 2012 | 2013 | 2014 | 2015 | Trend | Target: Industry | Target: Distributor |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Focus** Services are provided in a manner that responds to identified customer preferences. | **Service Quality** | New Residential/Small Business Services Connected on Time | | | | 100.00% | 98.40% | 100.00% | | 90.00% | |
| | | Scheduled Appointments Met On Time | | | | | | | | | |
| | | Telephone Calls Answered On Time | | | | | 95.00% | 98.70% | | 65.00% | |
| | **Customer Satisfaction** | First Contact Resolution | | | | | | N/A | | | |
| | | Billing Accuracy | | | | | 96.71% | 96.46% | | 98.00% | |
| | | Customer Satisfaction Survey Results | | | | | | 91.4% | | | |
| **Operational Effectiveness** Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives. | **Safety** | Level of Public Awareness | | | | | | 69.25% | | | |
| | | Level of Compliance with Ontario Regulation 22/04 [1] | | | | | | C | | | C |
| | | Serious Electrical Incident Index | Number of General Public Incidents | | | | | 0 | | | 0 |
| | | | Rate per 10, 100, 1000 km of line | | | | | 0.000 | | | 0.000 |
| | **System Reliability** | Average Number of Hours that Power to a Customer is Interrupted [2] | | | | 4.21 | 6.06 | 10.08 | | | 5.13 |
| | | Average Number of Times that Power to a Customer is Interrupted [2] | | | | 4.22 | 3.37 | 4.39 | | | 3.79 |
| | **Asset Management** | Distribution System Plan Implementation Progress | | | | | | 113.2% | | | |
| | **Cost Control** | Efficiency Assessment | | | | | | | | | |
| | | Total Cost per Customer [3] | | | | | | | | | |
| | | Total Cost per Km of Line [3] | | | | | | | | | |
| **Public Policy Responsiveness** Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board). | **Conservation & Demand Management** | Net Cumulative Energy Savings [4] | | | | | | | | | |
| | **Connection of Renewable Generation** | Renewable Generation Connection Impact Assessments Completed On Time | | | | | | | | | |
| | | New Micro-embedded Generation Facilities Connected On Time | | | | | | | | | |
| **Financial Performance** Financial viability is maintained; and savings from operational effectiveness are sustainable. | **Financial Ratios** | Liquidity: Current Ratio (Current Assets/Current Liabilities) | | 0.62 | 0.39 | 0.32 | 0.46 | 0.62 | | | |
| | | Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio | | | | | | | | | |
| | | Profitability: Regulatory Return on Equity | Deemed (included in rates) | | | | | | | | |
| | | | Achieved | | | | | | | | |

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

**Legend:**
5-year trend: up, down, flat
Current year: target met, target not met

# 2015 Scorecard Management Discussion and Analysis ("2015 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2015 Scorecard MD&A: **http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf**

## Scorecard MD&A - General Overview

Hydro One Remote Communities Inc. ("Remotes") is an integrated generation and distribution company serving 3,600 customers in 21 off-grid communities. These communities are isolated and scattered across Ontario's north. As compared to other Ontario distributors Remotes has unique financial, operational and geographical attributes.

Remotes is 100% debt financed and conducts its operations under a cost recovery model to achieve a breakeven result of operations. Any surplus or deficiency in revenues is added to or drawn from the Rural or Remote Rate Protection Variance Account for future disposition by the Ontario Energy Board ("OEB"). Fifteen of the communities are First Nations, which are served under agreements with the federal government. In these communities, the federal government funds capital associated with load growth. Replacement capital, operations, maintenance and administrative costs are funded through Remotes' revenue requirement.

Due to the lack of grid connection, most of the electricity that Remotes generated is from diesel technology, which is currently the most feasible smaller-scale generation technology for the communities served by Remotes. Remotes also operates two small run of the river hydroelectric plants and, at the end of 2015, had 6 customer/community-owned solar installations connected to its distribution systems. Fuel is Remotes' single largest cost. Fuel costs are inherently volatile, related to changes in commodity price, method of delivery and volumes required to generate electricity.

Thirteen communities are not accessible by year-round road and can only be reached by aircraft, winter road or, in the case of one community, barge. The size and isolation of Remotes' service territory means that transportation of fuel, equipment and staff are key cost drivers. Construction and project risk are high due to the lack of transportation infrastructure.

2015 marks Remotes' first scorecard. Because Remotes is an integrated generation company with unique financing and operations, some metrics are not included in the results. The Ontario Energy Board has recognized that Remotes is not directly comparable to other Ontario distributors. In its Decision in proceeding EB-2014-0084, the Board noted that, "Hydro One Remotes is excluded from the Board's benchmarking analysis because of its unique circumstances. As noted in Hydro One Remotes' 2014 Price Cap Incentive Rate application (proceeding EB-2013-0142), Hydro One Remotes is unique in terms of its operating characteristics and cost recovery due to the Rural or Remote Electricity Rate Protection."

## Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2015, Remotes processed 100 new connection requests for residential and small business low-voltage customers (those with service less than 750 Volts). 100% of these requests were completed within five business days (or as agreed to by the customer and the distributor), The industry target is 90%.

- **Scheduled Appointments Met On Time**

Because of high transportation costs and uncertainty about flight availability/ability to land, Remotes does not schedule appointments with customers. Work is generally organized through Band Councils or contractors since most customers do not have telephones. As a result, no appointments are missed or rescheduled.

- **Telephone Calls Answered On Time**

Remotes' billing and customer service staff received 9,952 phone calls from customers in 2015, answering 98.7% of these calls on time, as prescribed in the Ontario Energy Board's (OEB) Distribution System Code (DSC). The DSC requires call centre staff to answer calls within 30 seconds, 65%of the time, whenever the customer reaches an agent either directly or by means of a transfer. Remotes does not use an automated Interactive Voice Response (IVR) system.

## Customer Satisfaction

- **First Contact Resolution**

First Contact Resolution (FCR) reports the success of the distributor in resolving a customer's issue during the first contact. In 2015, Remotes designed a process to track FCR and will report 2016 performance next year. Remotes measures FCR based on the number of issues that can be resolved by the billing agent as compared to those that must be brought to a supervisor for resolution.

- **Billing Accuracy**

In 2015, Remotes issued 40,479 bills, with an accuracy rate of 96.46%. Remotes does not meet the industry standard of 98.00%. This is largely due to the fact that Remotes has not installed smart meters and relies on manual readings. Manual readings are more likely to result in higher planned and unplanned estimates. Remotes generally contracts with local community members to read the meters, and the readings are then faxed to the office and entered into the system by the billing team. If the faxed readings are late, they result in an unplanned estimate. There were 688 unplanned estimates in 2015. Remotes also has approximately 140 seasonal customers whose premises are generally difficult to access in the winter and who are billed quarterly with one physical meter read per year. In 2015, there were 413 planned estimates related to these customers.

- **Customer Satisfaction Survey Results**

Remotes engaged a professional research company with the ability to speak First Nation languages to conduct a random telephone survey of its customers in 2015. When asked “Overall, are you very satisfied, somewhat satisfied, dissatisfied or very dissatisfied with the electricity service you get from Hydro One Remotes,” 91.4% reported being satisfied or very satisfied. The major reasons for satisfaction were that ‘electricity is there when needed’ (64.5%) and ‘good/better services’ (19.5%). Dissatisfied customers said that expensive rates/bills were the major reason for dissatisfaction. As part of the survey, Remotes tested customer awareness of its programs, and asked customers for their opinions on how service could be improved. Actions are being taken to improve awareness of programs to reduce bills (Low-Income Emergency Assistance Program and Ontario Electricity Support Program) and to address the service improvements that customers identified. Along with asking customers service-related questions, information was also sought on the penetration of electric heat and air conditioning and customer access to the internet to help Remotes plan its programs. Remotes conducts biennial surveys of its customers to help it plan work and respond to customer priorities.

## Safety

- **Public Safety**

In April 2015, the Electrical Safety Authority (ESA) made recommendations to the OEB for a scorecard public safety measure that includes three main components: A) Public Awareness of Electrical Safety, B) Compliance with Ontario Regulation 22/04, and C) the Serious Electrical Incident Index. Components B and C were reported in previous years and results for *Component A – Public Awareness of Electrical Safety* were tracked for the first time in 2015, for reporting in 2016.

- **Component A – Public Awareness of Electrical Safety**

In the spring of 2016, Remotes engaged a professional research company with the ability to speak First Nation languages to conduct a random phone survey to gauge electrical safety awareness among people living in its service territory. The survey was designed by the ESA and assessed participants’ safety awareness in six core areas: the likelihood to call before digging, the impacts of touching a power line, safe distances when around power lines, safe distances when around downed power lines, danger of tampering with electrical equipment, and actions to be taken when an occupied vehicle is in contact with a power line. For 2015, the Company reported an overall index score of 69.25%. The score was determined by applying the index score to each response in the categories mentioned above, where "best answers" received a score of 1 and "incorrect answers" received a score of 0. Most respondents understood the danger of touching an overhead wire (84%) and tampering with electrical equipment (81.5%), but fewer were able to correctly identify in feet or meters how close they could come to an overhead line (17%). About the same number (18%) said they would call before digging (there are very few underground cables in Remotes' service territory). To improve the public's awareness of hazards, an ad campaign was launched on Wawatay radio during the summer of 2016 focusing on proximity to overhead wires. Remotes is also putting up safety hazard posters in central locations in communities, identifying common hazards, and plans an electrical safety poster contest in community schools for fall 2016. Previous (and ongoing) educational efforts included warning signs at hydroelectric and diesel generating stations, school presentations and information on electrical hazards in bill inserts.

- **Component B – Compliance with Ontario Regulation 22/04**

Remotes was assessed by the ESA as Compliant (C) to Ontario Regulation 22/04. Ontario Regulation 22/04 was introduced in early 2004 following recommendations from the ESA to ensure electrical safety and to track and report the safety records and compliance of electricity distributors. Distribution companies are required to submit declarations of compliance on the design, construction, and maintenance of distribution systems in accordance with the regulation, on an annual basis. An external auditor reviews and submits a final report, along with a signed declaration of compliance by an officer of the company, to the ESA for review and to establish a final result. The performance target for compliance with Ontario Regulation 22/04 is for the distributor to be fully compliant, and is recorded as Compliant (C), Non-Compliant (NC), or Needs Improvement (NI).

- **Component C – Serious Electrical Incident Index**

For 2015, the ESA identified no recordable serious public incidents, resulting in an index value of 0.0 for Remotes. The Serious Electrical Incident Index was designed to track and help improve public electrical safety on the distribution systems over time. Based on the distributor's total kilometers of line, the measure normalizes serious electrical incidents per 10, 100, or 1,000km of line reporting both the actual number and rate of incidents per kilometer – for Remotes, the index is normalized per 238 km of line. The distributor and any of its contractors or operators are required to report any serious electrical incident within 48 hours to the ESA. A serious electrical incident is defined as any electrical contact or any fire or explosion that caused or may have caused injury or death in any part of the distribution system operating at greater than 750 Volts (except if caused by lightning strikes). Remotes maintains a policy of reporting all public safety incidents to the ESA.

## System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

For 2015, Remotes reported an average distribution outage duration of 10.08 hours, representing an increase of about 4 hours from 2014. Performance was worse due primarily to an increase in planned outages (76% increase year over year). Planned outages were required to make improvements to the distribution systems, including pole replacement projects, the installation of viper switches (switches which allow us to sectionalize load within the distribution system) and bird protection. Community-wide outages were also required to increase transformer size and other distribution equipment in order to in-service Indigenous and Northern Affairs funded generation upgrades. Equipment failure also contributed to the poorer result. Bad weather prevented staff from flying into the community of Wapekeka to replace a burnt transformer, leading to a longer than normal outage (23.5 hours). We also experienced a longer than normal outage in one of our largest communities, Big Trout Lake (6.4 hours), related to a burnt switch at the station, which was compounded by a delay in securing a plane to the community. Finally, a lightning strike in Sultan resulted in a 26.1 hour outage as staff was not able to fix the problem due to the ongoing lightning storm. Remotes notes that, although not reflected on the scorecard, 2015 showed improvement in overall generation availability across its system. Planned distribution outages are expected to be higher in the next few years and are expected to improve reliability in the longer term. In particular, viper switches will improve cold load pickup related to loss of generation, will help reduce community-wide outages associated with catastrophic failure of a generation unit and will permit sectionalizing load to reduce the impact of community-wide distribution outages. Because the size of the generation in communities can limit the opportunity for new customers to connect to the systems, planned outages related to Indigenous and Northern Affairs Canada funded generation upgrades allow communities to grow and new services to connect to the distribution systems.

- **Average Number of Times that Power to a Customer is Interrupted**

Frequency of customer distribution outages was reported at 4.39 outages per customer for 2015, an increase of 30% compared to the previous year. Planned outages are expected to be higher in the next few years as increased work is required on the distribution systems to improve reliability in the longer-term. Planned outages were the major contributor to the increased frequency of interruptions to customers.

## Asset Management

- **Distribution System Plan Implementation Progress**

For 2015, the company exceeded its planned project expenditures by 13%, reflecting an increase in distribution system improvements. The Distribution System Plan (DSP) implementation progress is a distributor-defined performance metric. For Remotes, the DSP is the Company's forecasted distribution capital expenditures required to maintain and improve the distribution system over the next five years.

## Cost Control

The OEB has recognized that Remotes is not directly comparable to other Ontario distributors. In its decision in proceeding EB-2014-0084, the Board noted that, "Hydro One Remotes is excluded from the Board's benchmarking analysis because of its unique circumstances. As noted in Hydro One Remotes' 2014 Price Cap Incentive Rate application (proceeding EB-2013-0142), Hydro One Remotes is unique in terms of its operating characteristics and cost recovery due to the Rural or Remote Electricity Rate Protection."

## Conservation & Demand Management

- **Net Cumulative Energy Savings (Percent of target achieved)**

The Conservation First Framework is focused on reducing peak demand on the grid and is not related to Remotes' operations. As such, Remotes is excluded from the province-wide targets. Federal and provincial conservation programs that are designed to meet the unique needs of customers living in isolated communities in the far north are available to customers in Remotes' service territory. Remotes also has a small conservation program that focuses on energy efficient products and customer education about energy usage.

## Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

Due to technical challenges associated with integrating renewable generation in isolated distribution systems, the IESO FIT (Feed-in-Tariff) programs are not available to customers in Remotes' service territory. Remotes does offer a program to allow renewable generation to connect to its distribution systems, but, when they occur, most of the installations are smaller than 10 kW and do not require a Connection Impact Assessment (CIA).

- **New Micro-embedded Generation Facilities Connected On Time**

No installations were reported in 2015. This metric measures the company's success in connecting micro-embedded generation facilities (less than 10kW) 95% of the time within a five business day window.

## Financial Ratios

Remotes is 100% debt-financed and is operated as a break-even company with no meaningful return on equity. Therefore, given its financial structure, along with its unique operating characteristics, financial ratios are not comparable with those of other Ontario distribution utilities.

## Note to Readers of 2015 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

*FORWARD-LOOKING STATEMENTS AND INFORMATION*

Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "can", "believe," "seek," "estimate," 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. Some of the factors that could cause such differences include legislative or regulatory developments, an unexpected increase in call centre volumes, financial market conditions, general economic conditions and the weather. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

# SERVICE QUALITY AND RELIABILITY INDICATORS

## 1.0 INTRODUCTION

Subject to the exceptions and modifications noted below, Remotes currently monitors and records service quality indicators as required in Chapter 15 of the Ontario Energy Board 2006 Electricity Distribution Rate Handbook, dated May 11, 2005.

## 2.0 CUSTOMER SERVICE INDICATORS

Due to the distances between communities and the associated cost to transport staff and equipment, Remotes bundles work to reduce costs. Work is performed when staff have sufficient work in the community, or when they are in a nearby community. Planes are can often delayed flying into the communities, especially in the shoulder seasons of spring and fall. Remotes does not therefore make morning or afternoon appointments with customers or reschedule missed appointments. New connections are usually paid for and organized through the Band Offices. Therefore the Service Quality Index ("SQI") for new connections includes the bundling of work.

The Customer service indicators that Remotes is able to track are as follows:

<u>Connection of New Services:</u>
The percentage of customer connections of new services completed within five working days from the day on which all conditions of service are satisfied, including being able to schedule sufficient work in the community or in a nearby community to reduce the transportation costs as described above.

Emergency Response:

The percentage of responses to emergency trouble calls (including fire, ambulance, police) met within 120 minutes for rural utilities. The elapsed time is measured from the call to the arrival of qualified Remotes' service personnel, and includes Remotes' operators.

Written Response to Inquiries:

The percentage of responses to customers' (or an agent of the customer) requests for written information regarding their accounts that are met within ten working days of the request.

Telephone Accessibility

The percentage of incoming calls answered within thirty seconds by billing/customer service staff.

Telephone Call Abandon Rate

The percentage of incoming calls abandoned before being answered following the thirty second period described in Telephone Accessibility.

Reconnection Performance Standard

The percentage of reconnections of disconnected customers that are completed within two working weeks after the customer has made full payment of overdue amounts or has entered into a payment arrangement with Remotes.

Table 1 shows the customer service results for the historic years.

**Table 1**

**Customer Service Indicators**

| Performance Measure | *OEB* Target | 2012 Actual | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual |
|---|---|---|---|---|---|---|
| **Connection of New Services** (% completed in ≤ 5 days) | **≥ 90%** | 100% | 100% | 98.4% | 100% | 100% |
| **Emergency Response** (% responded to in ≤ 120 min ) | **≥ 80%** | 95.4% | 99.1% | 98.9% | 99.1% | 99.3% |
| **Written Response to Inquiries** (% responded to in ≤ 10 days) | **≥ 80%** | 100% | 100% | 100% | 100% | 99.9% |
| **Telephone Accessibility** (% answered within 30 seconds) | **≥ 65%** | - | - | 95.1% | 99.9% | 100% |
| **Telephone Call Abandon Rate** (% of calls abandoned) | **≤10%** | - | - | 1.3% | 0.5% | 0.0% |
| **Reconnection of Services on Time** (% of customers reconnected within 2 weeks of payment)[1] | **≥ 85%** | - | 100% | 100% | 93.2% | 94.9% |

Remotes has met the OEB targets in all of the metrics it is able to track. Remotes' phone system was not able to track call abandon rates or the time to answer calls until 2014, when a new phone system was installed. Remotes has tracked this indicator since the new system was installed.

## 3.0 SERVICE RELIABILITY INDICATORS

Interruption data is collected and recorded in Remotes' Thunder Bay Service Centre, through communications with plant operators and field staff involved in the interruption restoration, and through the SCADA system, which records generation related outages. The data on outages and service quality is used to analyze performance, and drive strategy and business investment decisions. Interruption data is used to calculate OEB

[1] This standard was determined through EB-2011-0021

reliability indices (including loss of supply) monthly, which are reported internally throughout the year. Line Managers and Supervisors meet monthly to review and analyze outages, identify patterns and look for solutions.

The two Service Reliability Indicators are as follows:

System Average Interruption Frequency Index (SAIFI):

The average number of times that customers served by Remotes were interrupted in the year. Due to the inherent lack of generation redundancy in an isolated system, service interruptions are more frequent in remote communities than in a grid connected context. Very short outages may be experienced when different generators are dispatched by the automated system.

System Average Interruption Duration Index (SAIDI):

The average numbers of hours that customers served by Remotes were without power in the year.

The above reliability indices measure all interruptions caused by planned and unplanned interruptions of 1 minute or more.

### 3.1 Major Event

For the purposes of OEB reporting, Remotes follows the IEEE standard for major events. The standard is derived by statistical analysis on the SAIDI value from each outage day over the past five years. If any daily SAIDI in the year exceeds that threshold, it is considered a major event day. The threshold is recalculated at the end of every year for the subsequent year. No major events have occurred over the past five years using that standard.

For the purposes of internal reporting, Remotes deems a major event to have occurred when a major catastrophic event beyond Remotes' control occurs that affects an entire community and 1) results in widespread system damage; or 2) an outage of at least twelve hours due to circumstances beyond the control of the company, (for example, as a result of adverse weather that prevents a plane from landing). A catastrophic event may be a storm or fire or any other problem that interrupts an entire community and causes a change in the normal restoration business processes. Results shown in Exhibit A, Tab 5, Schedule 1 are the results reported internally.

## 4.0 RELIABILITY SUMMARY RESULTS

Table 2 shows the service reliability over the periods 2012 to 2016 and the 5 year average including loss of supply. Table 3 shows outages related to the loss of supply and Table 4 shows outages related to distribution.

**Table 2**

**Service Reliability Indicators Including Loss of Supply**

| Index | Including outages caused by loss of supply | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | 2016 | Average |
| SAIDI | 16.116 | 11.932 | 8.486 | 13.303 | 12.170 | 12.401 |
| SAIFI | 11.193 | 15.685 | 14.021 | 11.691 | 13.059 | 13.130 |

### 4.1 Customer Hours of Interruption

In 2012, SAIDI performance including loss of supply was worse than average mainly because of multiple supply outages directly related to poor quality bio-diesel fuel. An in-depth tank cleaning and fuel filtering program were undertaken to reduce the impact to reliability and fuel suppliers were required to inspect and test fuel and equipment throughout all stages. This requirement is now a contract term. SAIDI performance was also adversely affected by several unplanned distribution outages described in more detail under Table 4 below.

In 2013 and 2014 SAIFI performance including loss of supply was worse than average mainly due to generation performance, discussed in more detail under Table 4 below.

**Table 3**

**Service Reliability Indicators Loss of Supply Only**

| Index | Outages caused by loss of supply | | | | | |
|---|---|---|---|---|---|---|
| | **2012** | **2013** | **2014** | **2015** | **2016** | **Average** |
| **SAIDI** | 8.167 | 7.724 | 2.418 | 3.220 | 3.063 | 4.918 |
| **SAIFI** | 7.552 | 11.467 | 10.649 | 7.304 | 8.114 | 9.017 |

As discussed above, 2012 SAIDI loss of supply performance was worse than average mainly related to multiple supply outages directly related to poor quality bio-diesel fuel as discussed above.

In 2013, SAIDI was worse than the five year average due to unplanned engine failures and defective equipment. A major outage occurred in Wapekeka related to a faulty main breaker that had to be replaced. In Kasabonika Lake, all three generators tripped when the A unit was put on line, leading to an extended outage as crews tried to get the power back on. Outages due to problems with the Programmable Logic Controller (“PLC”) in Sachigo Lake and an engine failure in Sandy Lake also contributed to the worse than average result.

In 2013, SAIFI was worse than average mainly due to problems with the C unit in Marten Falls, under voltage engine trips in Big Trout Lake, and various plant and engine issues in

Weagamow. In 2014, SAIFI was slightly worse than average mainly due to PLC issues with generation switching and controls in Sandy Lake.

**Table 4**
**Service Reliability Indicators Excluding Loss of Supply**

| Index | Excluding outages caused by loss of supply | | | | | |
|---|---|---|---|---|---|---|
| | **2012** | **2013** | **2014** | **2015** | **2016** | **Average** |
| **SAIDI** | 7.949 | 4.208 | 6.068 | 10.083 | 9.107 | 7.483 |
| **SAIFI** | 3.641 | 4.218 | 3.372 | 4.387 | 4.945 | 4.113 |

SAIDI excluding loss of supply was worse than average in 2012 due to a house fire in Sandy Lake that required the local operator to shut down the generating station to make the area safe for emergency personnel, and because of a defective switch on the hard-to-reach line along the rail tracks from Armstrong to Collins that led to two long outages. The first outage caused by the defective switch was handled by the local operator, but the switch went out again a couple of weeks later, requiring a line crew to address the problem. A lightning strike in Webequie that blew the fuse at the step-up transformer, three switches in Big Trout Lake that opened for an undetermined cause, and a planned outage to replace a broken cross arm in Webequie also led to longer than average outages.

In 2015, SAIDI excluding loss of supply increased by about four hours from 2014 and about three hours compared to the average. Performance was worse than average primarily due to an increase in planned outages (76% increase year over year). Planned outages were required to make improvements to the distribution systems, including pole replacement projects, the installation of viper switches (switches which improve cold load pickup after a generation outage) and bird protection. Community-wide outages were also required to increase transformer size and other distribution equipment in order to in-service Indigenous and Northern Affairs funded generation upgrades. Equipment failures also contributed to the poorer result. Bad weather prevented staff from flying into the community of Wapekeka to replace a burnt transformer, leading to a longer than normal outage (23.5 hours). There was also a longer than normal outage in one of the largest communities, Big Trout Lake (6.4 hours), related to a burnt switch at the station, which was compounded by a delay in securing a plane to fly to the community. Finally, a lightning strike in Sultan resulted in a 26.1 hour outage as staff was not able to fix the problem and restore power due to the ongoing lightning storm.

In 2016, SAIDI performance was worse than the five year average but better than 2015 mainly related to a continued emphasis on planned outages and because of equipment failure. Planned outages contributed slightly less to the SAIDI result than in 2015, but were higher than average over the period and related to a pole replacements, installation of viper switches and installation of bird protection. Defective equipment also contributed to the worse than average result, but was better than performance in 2015. In Armstrong, there was a long outage caused by the failure of the potential transformers located on the station transformer. The length of outage was compounded by bad weather that delayed the crew from getting to site. In Weagamow, the operator took a station outage in the middle of the night related to a fire on the step up structure outside the plant caused by leaking insulators. The power was temporarily turned back on to allow the air ambulance to land and was turned off again. A crew was dispatched to replace the insulators the same night.

In 2013, SAIFI was slightly above average due to a relatively higher number of bird strikes. In 2015 and 2016, higher SAIFI relates to the increase in planned outages and to equipment failure.

## 5.0 OUTAGES BY CAUSE CODE BY YEAR AND MONTH

The following figures demonstrate the customer interruptions sustained on an annual basis by cause code.

<u>2012 Customer Interruptions</u>

Figures 1 to 4 illustrate the customer interruptions sustained in 2012 by cause code.

**2012 Number of Customers Interrrupted**

| Cause of Interruption | Total Outages | Percent |
|---|---|---|
| 0 - Unknown/Other | 1,109 | 2.8% |
| 1 - Scheduled Outage | 7,880 | 20.0% |
| 2 - Loss of Supply | 26,169 | 66.5% |
| 3 - Tree Contacts | 338 | 0.9% |
| 4 - Lightning | 552 | 1.4% |
| 5 - Defective Equipment | 1,569 | 4.0% |
| 6 - Adverse Weather | 11 | 0.0% |
| 7 - Adverse Environment | 1,715 | 4.4% |
| 8 - Human Element | 0 | 0.0% |
| 9 - Foreign Interference | 13 | 0.0% |
| **Total All Causes** | **39,356** | **100%** |

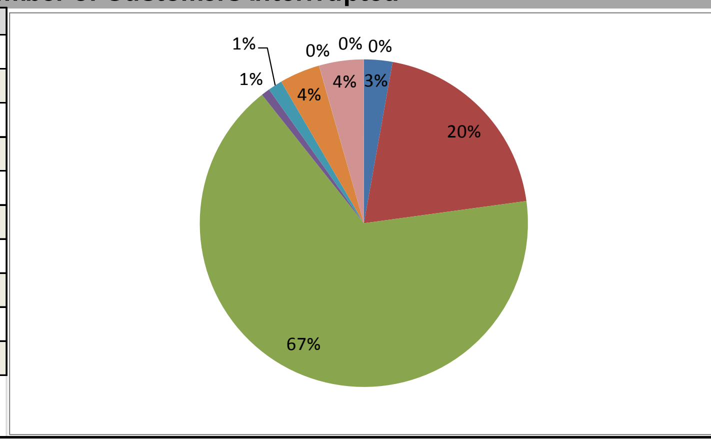



**Figure 1 - 2012 Number of Customers Interrupted by Cause Code**

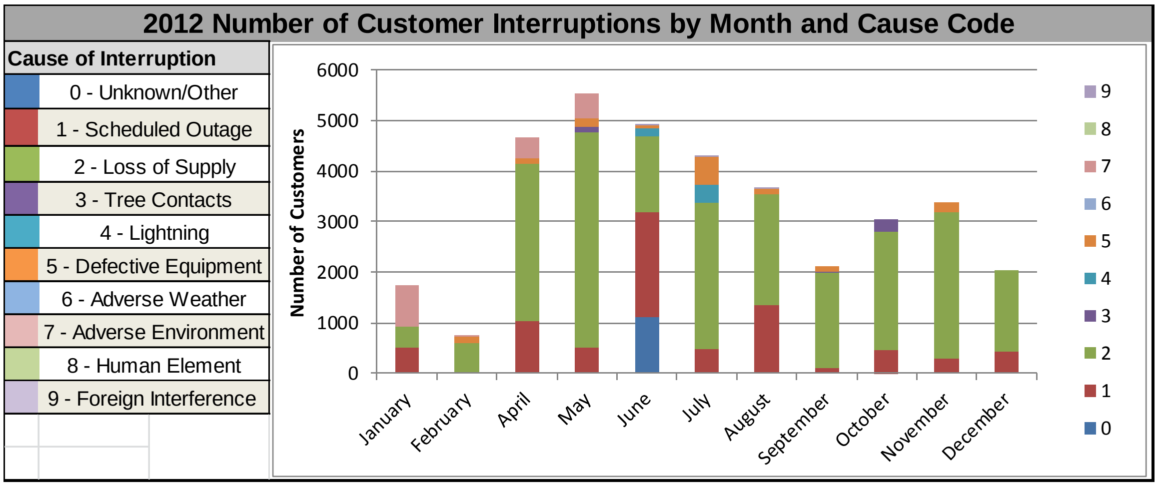



**Figure 2 - 2012 Number of Customer Interruptions by Month and Cause Code**

**2012 Number of Hours Customers Interrrupted**

| Cause of Interruption | Total Outages | Percent |
|---|---|---|
| 0 - Unknown/Other | 3,519 | 6.2% |
| 1 - Scheduled Outage | 10,692 | 18.9% |
| 2 - Loss of Supply | 28,589 | 50.5% |
| 3 - Tree Contacts | 1,112 | 2.0% |
| 4 - Lightning | 3,392 | 6.0% |
| 5 - Defective Equipment | 6,917 | 12.2% |
| 6 - Adverse Weather | 57 | 0.1% |
| 7 - Adverse Environment | 2,275 | 4.0% |
| 8 - Human Element | - | 0.0% |
| 9 - Foreign Interference | 29 | 0.1% |
| **Total All Causes** | **56,582** | **100%** |

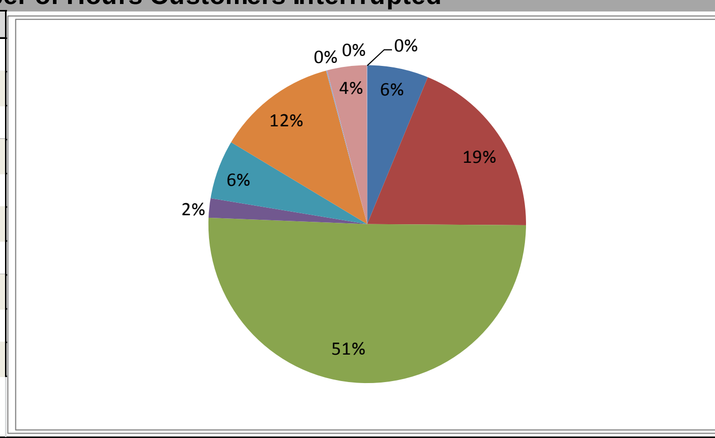



**Figure 3 - 2012 Customer Hours of Interruption by Cause Code**

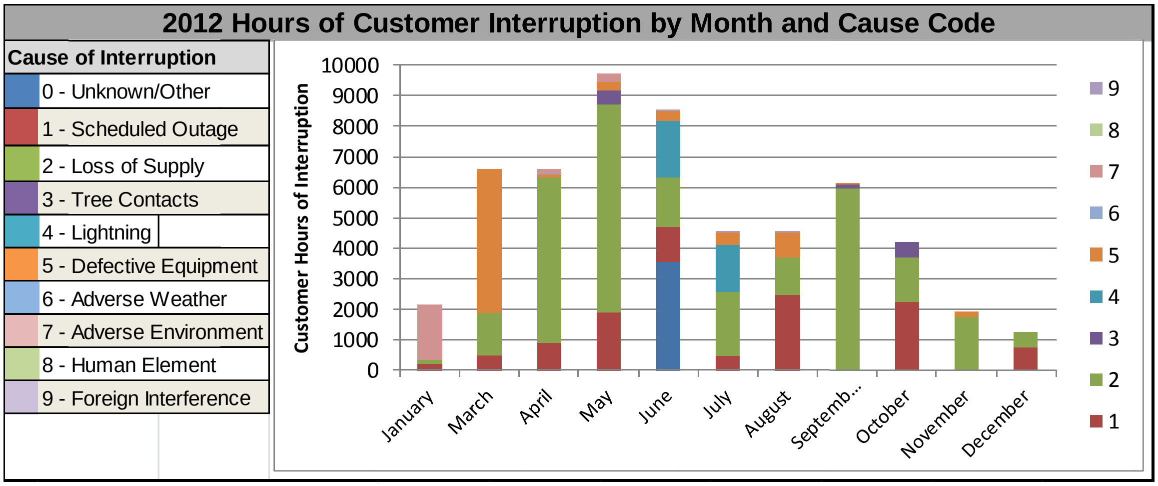



**Figure 4 - 2012 Customer Hours of Interruption by Month and Cause Code**

2013 Customer Interruptions

Figures 5 to 8 illustrate the customer interruptions sustained in 2013 by cause code.

**2013 Number of Customers Interrupted**

| Cause of Interruption | Total Outages | Major Events |
|---|---|---|
| 0 - Unknown/Other | 1,462 | 2.6% |
| 1 - Scheduled Outage | 5,376 | 9.7% |
| 2 - Loss of Supply | 42,714 | 77.3% |
| 3 - Tree Contacts | 35 | 0.1% |
| 4 - Lightning | 392 | 0.7% |
| 5 - Defective Equipment | 935 | 1.7% |
| 6 - Adverse Weather | 29 | 0.1% |
| 7 - Adverse Environment | 7 | 0.0% |
| 8 - Human Element | 2,140 | 3.9% |
| 9 - Foreign Interference | 2,140 | 3.9% |
| Total All Causes | 55,230 | 100.0% |

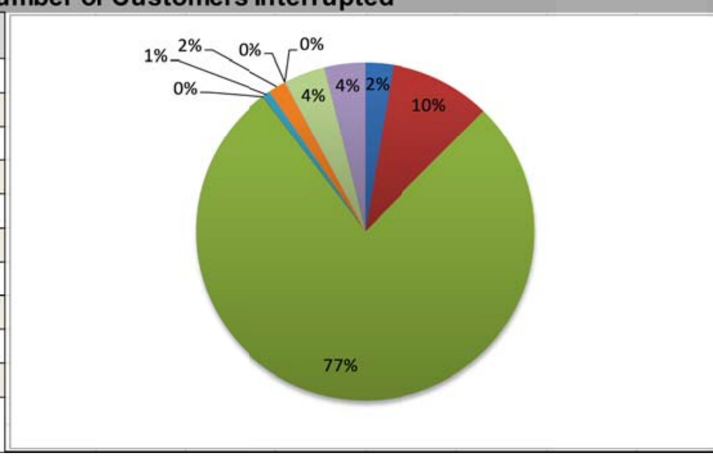



**Figure 5 - 2013 Number of Customers Interrupted by Cause Code**

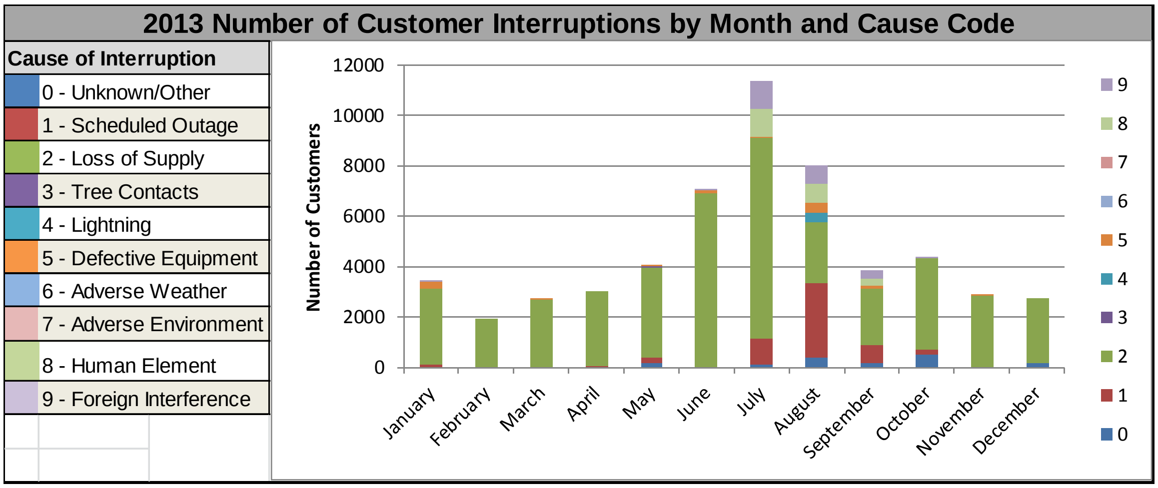



**Figure 6 - 2013 Number of Customer Interruptions by Month and Cause Code**

2013 Number of Customer Hours Interrupted

| Cause of Interruption | Total Outages | Percent |
|---|---|---|
| 0 - Unknown/Other | 1,077 | 2.6% |
| 1 - Scheduled Outage | 9,461 | 22.5% |
| 2 - Loss of Supply | 25,848 | 61.5% |
| 3 - Tree Contacts | 6 | 0.0% |
| 4 - Lightning | 291 | 0.7% |
| 5 - Defective Equipment | 2,407 | 5.7% |
| 6 - Adverse Weather | 172 | 0.4% |
| 7 - Adverse Environment | 119 | 0.3% |
| 8 - Human Element | 1,322 | 3.1% |
| 9 - Foreign Interference | 1,322 | 3.1% |
| Total All Causes | 42,023 | 100.0% |

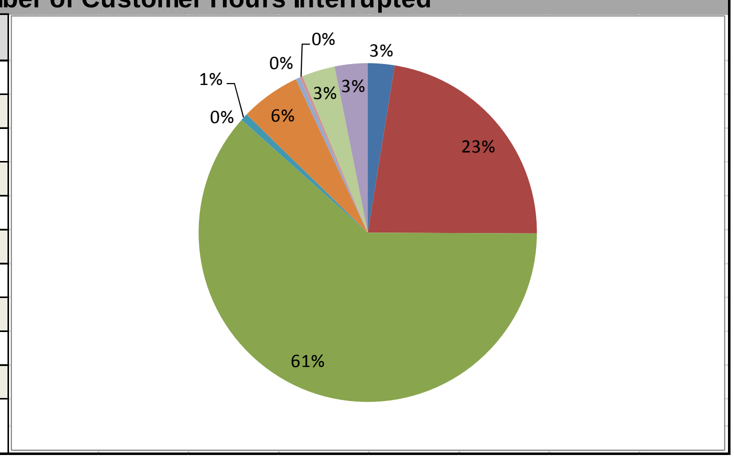



**Figure 7 - 2013 Hours of Customer Interruptions by Cause Code**

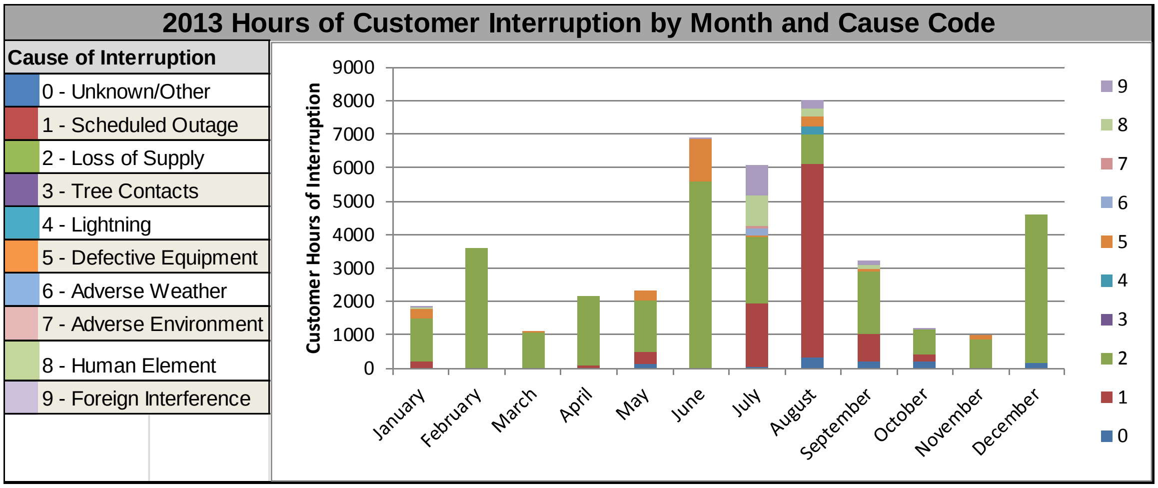



**Figure 8 - 2013 Hours of Customer Interruptions by Month and Cause Code**

<u>2014 Customer Interruptions</u>

Figures 9 to 12 illustrate the customer interruptions sustained in 2014 by cause code.

**2014 Number of Customers Interrupted**

| Cause of Interruption | Total Outages | Percent |
|---|---|---|
| 0 - Unknown/Other | 2,397 | 4.8% |
| 1 - Scheduled Outage | 3,312 | 6.7% |
| 2 - Loss of Supply | 37,557 | 76.0% |
| 3 - Tree Contacts | 315 | 0.6% |
| 4 - Lightning | 6 | 0.0% |
| 5 - Defective Equipment | 681 | 1.4% |
| 6 - Adverse Weather | 2 | 0.0% |
| 7 - Adverse Environment | - | 0.0% |
| 8 - Human Element | 1 | 0.0% |
| 9 - Foreign Interference | 5,175 | 10.5% |
| **Total All Causes** | **49,446** | **100%** |

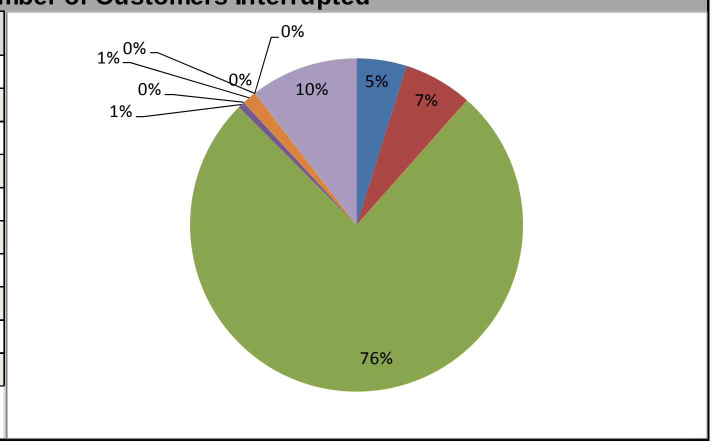



**Figure 9 - 2014 Number of Customers Interrupted by Cause Code**

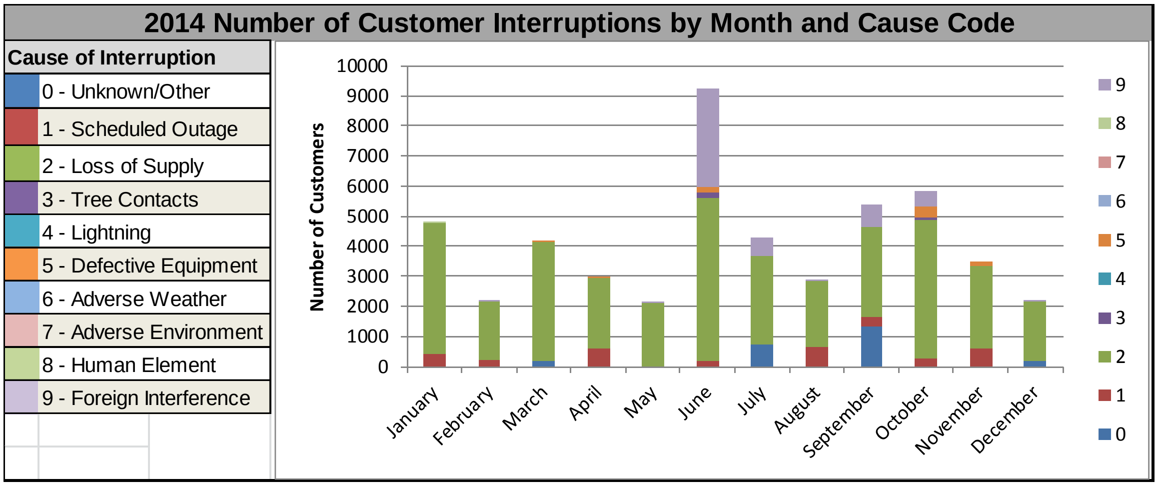



**Figure 10 - 2014 Number of Customer Interruptions by Month and Cause Code**

**2014 Number Customer-hours Interruptions**

| Cause of Interruption | Total Outages | Percent |
|---|---|---|
| 0 - Unknown/Other | 1,066 | 3.6% |
| 1 - Scheduled Outage | 8,650 | 28.9% |
| 2 - Loss of Supply | 8,532 | 28.5% |
| 3 - Tree Contacts | 1,918 | 6.4% |
| 4 - Lightning | 60 | 0.2% |
| 5 - Defective Equipment | 4,505 | 15.1% |
| 6 - Adverse Weather | 2 | 0.0% |
| 7 - Adverse Environment | - | 0.0% |
| 8 - Human Element | - | 0.0% |
| 9 - Foreign Interference | 5,189 | 17.3% |
| **Total All Causes** | **29,922** | **100%** |

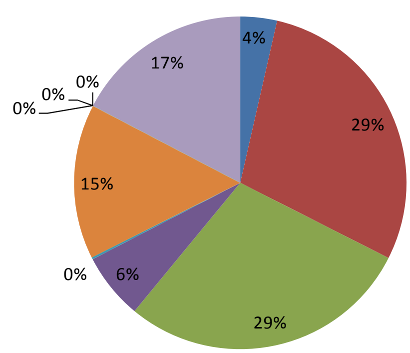



**Figure 11 - 2014 Customer hours of interruption by Cause Code**

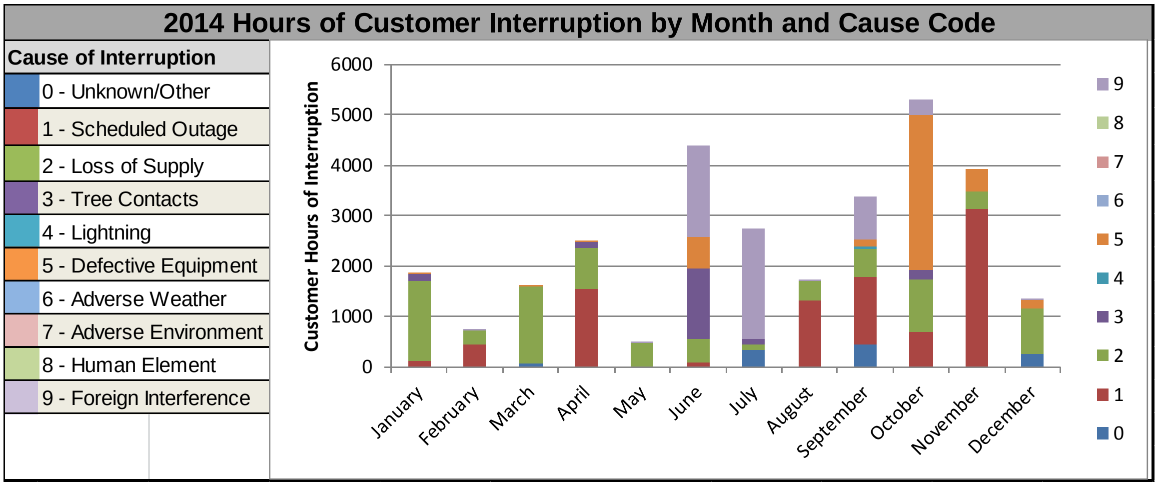



**Figure 12 - 2014 Customer Hours of Interruption by Month and Cause Code**

<u>2015 Customer Interruptions</u>

Figures 13 to 16 illustrate the customer interruptions sustained in 2015 by cause code.

**2015 Number of Customers Interrupted**

| Cause of Interruption | Total Outages | Percent |
|---|---|---|
| 0 - Unknown/Other | 2,451 | 5.9% |
| 1 - Scheduled Outage | 6,277 | 15.2% |
| 2 - Loss of Supply | 25,854 | 62.5% |
| 3 - Tree Contacts | 188 | 0.5% |
| 4 - Lightning | 958 | 2.3% |
| 5 - Defective Equipment | 2,976 | 7.2% |
| 6 - Adverse Weather | 194 | 0.5% |
| 7 - Adverse Environment | - | 0.0% |
| 8 - Human Element | - | 0.0% |
| 9 - Foreign Interference | 2,489 | 6.0% |
| Total All Causes | 41,387 | 100% |

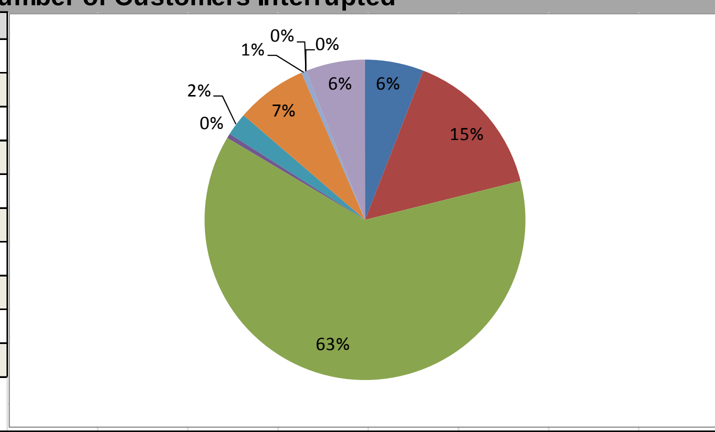



**Figure 13 - 2015 Number of Customers Interrupted by Cause Code**

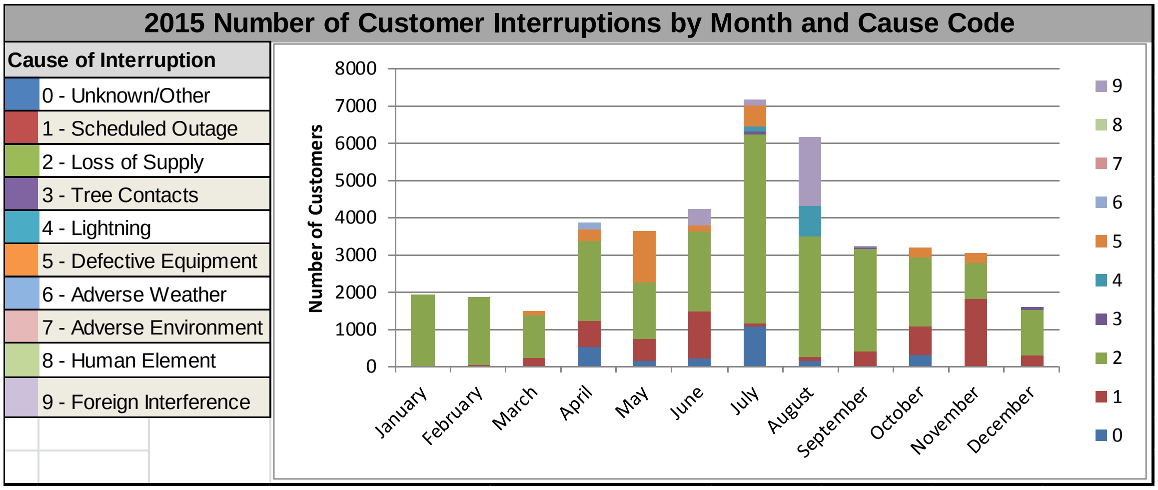



**Figure 14 - 2015 Number of Customer Interruptions by Month and Cause Code**

**2015 Number Customer-hours Interruptions**

| Cause of Interruption | Total Outages | Percent |
|---|---|---|
| 0 - Unknown/Other | 2,580 | 5.5% |
| 1 - Scheduled Outage | 15,286 | 32.4% |
| 2 - Loss of Supply | 11,399 | 24.2% |
| 3 - Tree Contacts | 2,548 | 5.4% |
| 4 - Lightning | 2,734 | 5.8% |
| 5 - Defective Equipment | 11,022 | 23.4% |
| 6 - Adverse Weather | 223 | 0.5% |
| 7 - Adverse Environment | - | 0.0% |
| 8 - Human Element | - | 0.0% |
| 9 - Foreign Interference | 1,324 | 2.8% |
| **Total All Causes** | **47,117** | **100%** |

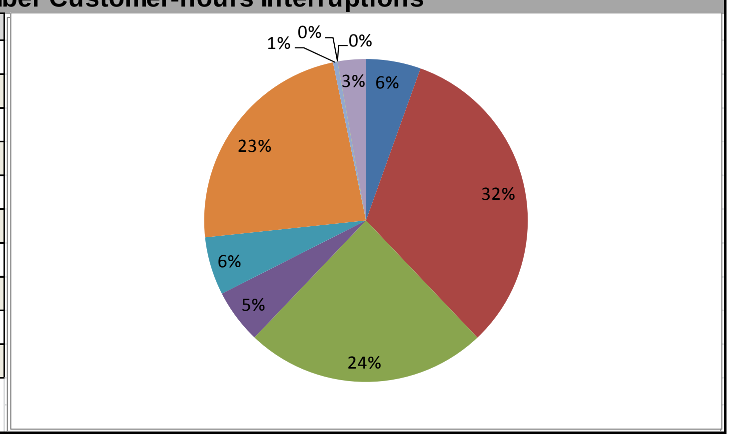



**Figure 15 - 2015 Number of Customer Hours of Interruption by Cause Code**

**2015 Hours of Customer Interruption by Month and Cause Code**

| Cause of Interruption |
|---|
| 0 - Unknown/Other |
| 1 - Scheduled Outage |
| 2 - Loss of Supply |
| 3 - Tree Contacts |
| 4 - Lightning |
| 5 - Defective Equipment |
| 6 - Adverse Weather |
| 7 - Adverse Environment |
| 8 - Human Element |
| 9 - Foreign Interference |

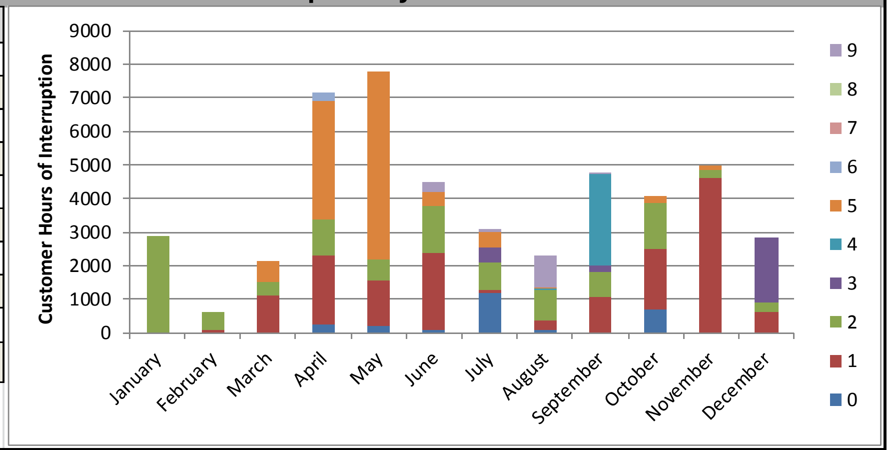



**Figure 16 - 2015 Customer Hours of Interruption by Month and Cause Code**

## 2016 Customer Interruptions

Figures 17 to 20 illustrate the customer interruptions sustained in 2013 by cause code.

**2016 Number of Customers Interrupted**

| Cause of Interruption | Total Outages | Percent |
|---|---|---|
| 0 - Unknown/Other | 2,017 | 4.3% |
| 1 - Scheduled Outage | 8,441 | 18.2% |
| 2 - Loss of Supply | 28,868 | 62.1% |
| 3 - Tree Contacts | - | 0.0% |
| 4 - Lightning | 759 | 1.6% |
| 5 - Defective Equipment | 2,716 | 5.8% |
| 6 - Adverse Weather | 1 | 0.0% |
| 7 - Adverse Environment | 1,971 | 4.2% |
| 8 - Human Element | - | 0.0% |
| 9 - Foreign Interference | 1,701 | 3.7% |
| Total All Causes | 46,474 | 100% |

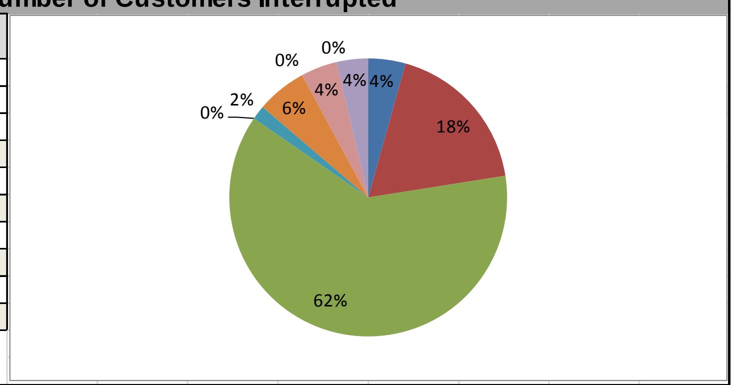



**Figure 17 - 2016 Number of Customers Interrupted by Cause Code**

**2016 Number of Customer Interruptions by Month and Cause Code**

| Cause of Interruption |
|---|
| 0 - Unknown/Other |
| 1 - Scheduled Outage |
| 2 - Loss of Supply |
| 3 - Tree Contacts |
| 4 - Lightning |
| 5 - Defective Equipment |
| 6 - Adverse Weather |
| 7 - Adverse Environment |
| 8 - Human Element |
| 9 - Foreign Interference |

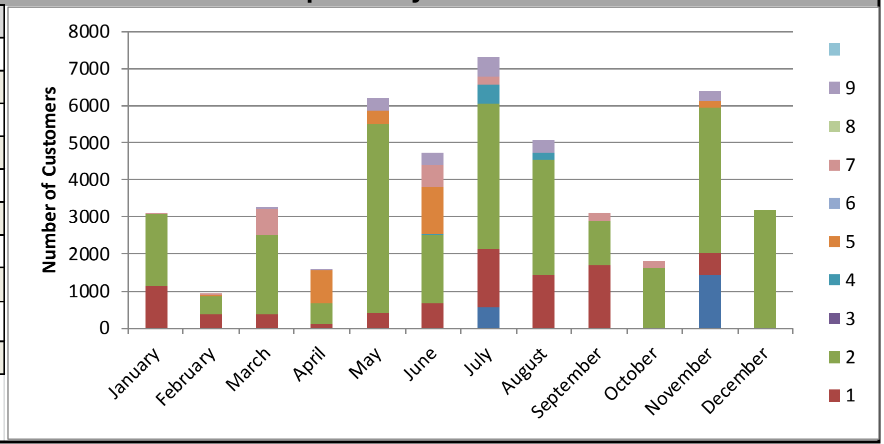



**Figure 18 - 2016 Number of Customer Interruptions by Month and Cause Code**

**2016 Number Customer-hours Interruptions**

| Cause of Interruption | Total Outages | Percent |
|---|---|---|
| 0 - Unknown/Other | 1,337 | 3.1% |
| 1 - Scheduled Outage | 15,203 | 35.1% |
| 2 - Loss of Supply | 10,906 | 25.2% |
| 3 - Tree Contacts | - | 0.0% |
| 4 - Lightning | 2,473 | 5.7% |
| 5 - Defective Equipment | 9,945 | 22.9% |
| 6 - Adverse Weather | 1 | 0.0% |
| 7 - Adverse Environment | 2,111 | 4.9% |
| 8 - Human Element | - | 0.0% |
| 9 - Foreign Interference | 1,367 | 3.2% |
| **Total All Causes** | **43,343** | **100%** |

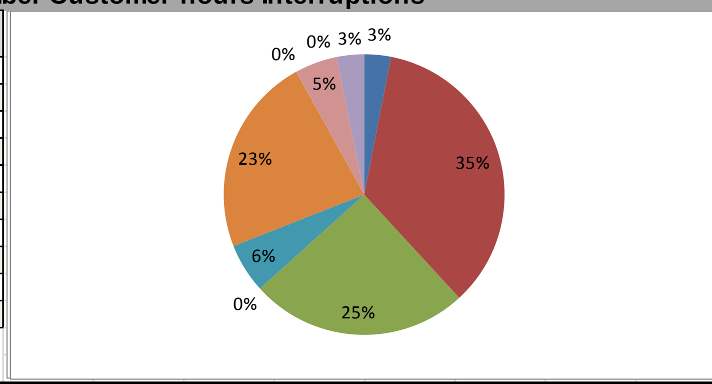



**Figure 19 - 2016 Customer Hours of Interruption by Cause Code**

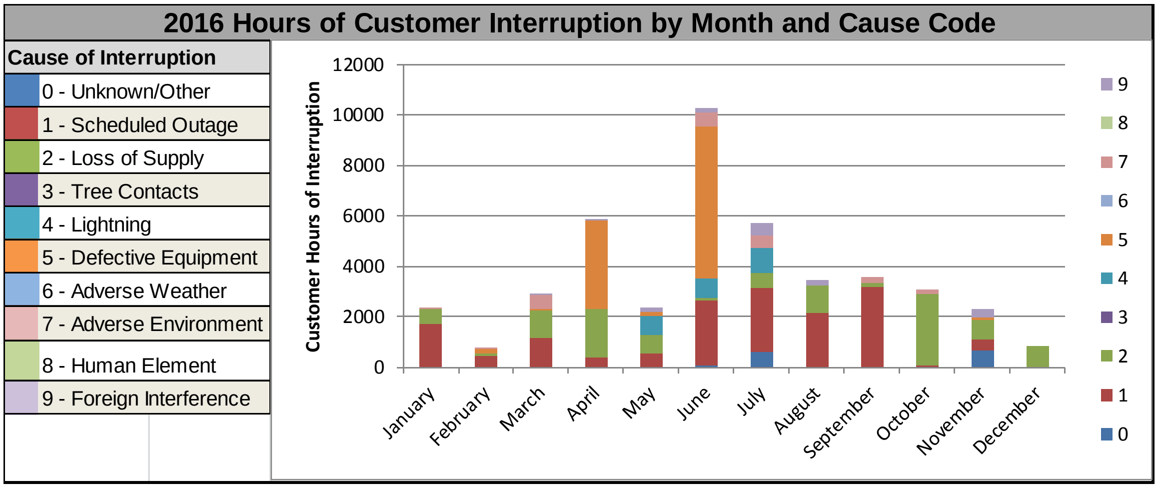



**Figure 20 - 2016 Customer Hours of Interruption by Month and Cause Code**

# Appendix 2-G
# Service Reliability and Quality Indicators
# 2012 - 2016

## Service Reliability

| Index | Including outages caused by loss of supply | | | | | Excluding outages caused by loss of supply | | | | | Excluding Major Event Days | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | 2016 | 2012 | 2013 | 2014 | 2015 | 2016 | 2012 | 2013 | 2014 | 2015 | 2016 |
| SAIDI | 16.116 | 11.932 | 8.486 | 13.303 | 12.170 | 7.949 | 4.208 | 6.068 | 10.083 | 9.107 | 16.116 | 11.932 | 8.486 | 13.303 | 12.170 |
| SAIFI | 11.193 | 15.685 | 14.021 | 11.691 | 13.059 | 3.641 | 4.218 | 3.372 | 4.387 | 4.945 | 11.193 | 15.685 | 14.021 | 11.691 | 13.059 |

No Major Event Days based on IEEE Standard

**5 Year Historical Average**

| | Including outages caused by loss of supply | Excluding outages caused by loss of supply | Excluding Major Event Days |
|---|---|---|---|
| SAIDI | 12.401 | 7.483 | 12.401 |
| SAIFI | 13.130 | 4.113 | 13.130 |

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

## Service Quality

| Indicator | OEB Minimum Standard | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|
| Low Voltage Connections | 90.0% | 100.0% | 100.0% | 98.4% | 100.0% | 100.0% |
| High Voltage Connections | 90.0% | | | | | |
| Telephone Accessibility | 65.0% | N/A | N/A | 95.1% | 99.9% | 100.0% |
| Appointments Met | 90.0% | | | | | |
| Written Response to Enquires | 80.0% | 100.0% | 100.0% | 100.0% | 100.0% | 99.9% |
| Emergency Urban Response | 80.0% | | | | | |
| Emergency Rural Response | 80.0% | 95.4% | 99.1% | 98.9% | 99.1% | 99.3% |
| Telephone Call Abandon Rate | 10.0% | N/A | N/A | 1.3% | 0.5% | 0.0% |
| Appointment Scheduling | 90.0% | | | | | |
| Rescheduling a Missed Appointment | 100.0% | | | | | |
| Reconnection Performance Standard | 85.0% | N/A | 100.0% | 100.0% | 93.2% | 94.9% |

Remotes does not have high voltage connections.
Remotes does not make appointments with customers. Due to the inaccessibiity of its service territory, work is bundled and performed when a crew is in the community.
Remotes' telephone system was not able to track telephone calls. In 2014, the system was replaced and this metric has since been tracked.
As determined in EB-2011-0021, the reconnection performance standard for Remotes is 2 weeks, to allow for work to be bundled and performed when a crew is in the community.
Connection of new services low voltage does not include connection of micro-embedded generation facilities.
Reconnection Performance Standard was not tracked until 2013, when the Board issued its Decision on EB-2011-0021

# AFFILIATE SERVICE AGREEMENTS

## 1.0 INTRODUCTION

In accordance with the Affiliate Relationships Code ("ARC"), when Remotes provides services to or purchases services from affiliates, it does so in accordance with service agreements that meet the ARC requirements. This Exhibit describes the current agreements between Remotes and its affiliates, and the pricing for these services.

## 2.0 COMMON CORPORATE COSTS

Hydro One has identified certain Common Corporate Functions and Services ("CCF&S") that provide common benefits to all business units while minimizing costly and unnecessary duplication.

Costs provided under the shared services model include CCF&S (e.g. legal, finance and human resources), Telecommunications Services (telephone, fax and internet services for the Thunder Bay service centre and at each of the remote community sites); Enterprise Technology Services (outsourced services provided by Inergi LP related to IT systems, accounts payable, payroll, billing and financial IT systems and desk side support); Supply Management Services, and Customer System Operations (customer billing) and the use of shared SAP assets.

Common corporate functions and services include Corporate Management, Finance, Internal Audit, Tax, Legal, Corporate Secretariat, Regulatory, Corporate Communications and Services, First Nation and Metis Relations, Security, Human Resources and Labour Relations.

In 2004, Black & Veatch ("B&V") was engaged by Hydro One to recommend a best practice methodology to distribute Common Corporate Costs to Hydro One and its subsidiaries and partnerships. The methodology is based on clearly articulated shared services and an established cost allocation approach based on cost causality and benefit principles. This Common Corporate Cost Allocation is supported by a recent B&V Review of Common Corporate Costs in 2015 prepared for Hydro One Networks Transmission (EB-2016-0160) and a later Review of Common Corporate Costs prepared for Hydro One Networks Distribution (EB-2017-0049).

To allocate the cost, Networks:

- Identifies the functions and services included in the common costs;
- Identifies the activities performed to provide each of the tasks;
- Determines the budgeted costs; and
- Distributes the cost of each activity based on cost drivers when direct assignment is not possible.

Information on the costs for these services can be found in Exhibit D1, Tab 1, Schedule 6 and in the supporting schedules.

**Table 1**

**Service Level Agreements – 2017**

| Services Provider | Services Recipient(s) | Description of Services |
|---|---|---|
| Hydro One Inc. | Networks<br><br>Telecom<br><br>Remotes<br><br>Sault Ste. Marie | a) **General Counsel & Secretary Services –** Professional legal advice and input as well as guidance on business ethics and support in the form of a business code of conduct.<br>b) **President / CEO / Chairman Services –** Strategic direction and management.<br>c) **Chief Financial Officer Services –** Review of policies and procedures, investment decisions, treasury operations and tax planning, financial control and reporting.<br>d) **General Counsel and Secretary Services –** Professional legal advice and input and services regarding the protection of assets and management of security risks.<br>e) **Financial Services –** Financial information, business planning, budgeting and financial reporting as well as other financial services such as treasury/pension/investor relations, taxation, financial systems and services, cost and inventory accounting, decision support, transaction processing (accounts payable and receivable), and fixed asset and general accounting.<br>f) **Corporate Services –** provides services related to human resource and labour relations, protection of assets, information management, leadership and consultation support related to First Nations and Metis communities and corporate communications.<br>g) **Telecommunications Services –** Field and engineering, logistics, corporate, construction, telecommunication and information technology services.<br>h) **Other Services –** Customer services operation and information management services.<br>i) **System Services –** use of the Services Provider's core business systems.<br>j) **Lease of Computer Equipment used to provide System Services –** leases from the Service Provider computer servers which house the Systems. |

## 3.0 UTILITY SERVICES PERFORMED BY NETWORKS

Remotes also purchases services from Networks related to utility operations. Costs for these services are purchased based on the hourly labour rate and the cost of materials and include lines and forestry work, drafting, environmental and engineering support, technical training and flight safety services.

| Services Provider | Services Recipient(s) | Description of Services |
|---|---|---|
| Networks | Remotes | **Utility Operations services** – Provincial lines, forestry, drafting, environmental compliance reviews and support, certificate of approval amendments, legislative review, support for land assessment and remediation, fleet management, maintenance repair and rental, flight safety, technical/trades training and support, safety, meter services, approval of plans, drawings and specification of installation work, and engineering and construction services. |
| Networks | Remotes | **Supply Chain Services** – Implementation of demand planning, management and procurement, process development, data management and warehousing. |

Utility services are demand-based and vary with the work program and the availability of Networks staff to perform work. The costs for utility services are built into the work programs and are based on time and materials. Costs for the historic, bridge and test years are shown in Appendix 2-N at Exhibit D2, Tab 4, Schedule 1.

## 4.0 UTILITY SERVICES PERFORMED BY REMOTES FOR NETWORKS

Remotes performs work for Networks based on demand and staff availability. Work includes lines work, lines training and metering work. Costing for this work is described in Exhibit D1, Tab 5, Schedule 1 the specific revenues for this work are shown in Exhibit G2, Tab 2, Schedule 1.

| Services Provider | Services Recipient(s) | Description of Services |
|---|---|---|
| Remotes | Networks | Metering and Lines Services – Metering/Technician/Lines work including meter installation, smart meter changes, line layout, estimating and staking, voltage/current surveys, power line maintenance, construction and repair, trouble call response, storm damage repairs, apprenticeship program instruction services. |

# GENERAL COUNSEL AND SECRETARY SERVICES, PRESIDENT/CEO/CHAIRMAN SERVICES/CHIEF FINANCIAL OFFICER

To be filed at a later date.

# GENERAL COUNSEL AND SECRETARY SERVICES, FINANCIAL SERVICES, CORPORATE SERVICES, TELE-COMMUNICATIONS-RELATED SERVICES, OTHER

To be filed at a later date.

**THIS AGREEMENT** made in duplicate as of the 1st day of January, 2017 (the "Effective Date").

**BETWEEN:**

**HYDRO ONE NETWORKS INC.**
**(the "Services Provider")**

**- and -**

**HYDRO ONE REMOTE COMMUNITIES INC.**
**(the "Services Recipient")**

## 1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to the Services Recipient by the Services Provider in accordance with the terms and conditions herein. Except as otherwise specified, the term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

## 2.0 SERVICES

The Services Provider shall provide the following types of services to the Services Recipient, which collectively constitute the Services and which are more particularly described in Schedule "A" attached hereto, as may be required by the Services Recipient from time to time during the term of this Agreement:

- Forestry services
- Metering services
- Work Methods and Training services
- Provincial Lines services
- Safety services
- Fleet services
- Environmental services
- Engineering Services
- Flight safety services
- Distribution Planning Technical services
- Joint Use services
- Health and Safety Services

## 3.0 DEFINITIONS

In this Agreement, including the recitals and Schedules hereto, in addition to terms defined elsewhere in this Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

(a) "**Agreement**" means this Agreement between the Services Recipient and the Services Provider and shall include Schedules "A", "B", "C", "D", "E" and "F" attached hereto and any amendments to the body of this Agreement and to the Schedules.

(b) **"Substantial Performance of the Services"** means the point at which the Services are ready for use or are being used by the Services Recipient for the purpose intended.

## 4.0 FEES PAYABLE

(a) The price for the performance of the Services described in Schedule "C" hereto shall be as specified in the said Schedule "C" and shall be exclusive of any sales and use taxes as may be applicable. In the event that the parties agree that the Services Recipient shall pay the Services Provider for the Services on a time and materials basis, such time and materials basis shall be in accordance with the Services Provider's 2017-2018 hourly rates by job category and fleet rates, which hourly rates and fleet rates may be amended from time to time by mutual agreement of the parties. The parties acknowledge and agree that the Services Recipient has received the Services Provider's 2017-2018 hourly and fleet rates from the Services Provider.

The parties agree that the price for the Services shall be paid by the Services Recipient to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party or by direct time reporting through Hydro One Inc.'s payroll system.

(b) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the *Excise Tax Act (Canada)*, as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for purposes of HST. For the purposes of this Agreement, "HST" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the Act, as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

## 5.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:

(i) it has all the necessary corporate power, authority and capacity to enter into this Agreement and to perform its obligations hereunder;

(ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider;

(iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services; and

(iv) all material, tools, machinery and equipment provided by the Services Provider to the Services Recipient as part of the Services shall be new and of a quality best suited to the purpose required and their use subject to the approval of the Services Recipient.

(b) The Services Recipient represents and warrants that:

(i) it has all the necessary corporate power, authority and capacity to enter into this Agreement and to perform its obligations hereunder; and

(ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

## 6.0 PERFORMANCE OF THE SERVICES

(a) **Access to Site:** For each type of Services to be performed, the Services Recipient shall provide the Services Provider with an opportunity to visit and examine the site at which the said type of Services are to be performed prior to commencement of the performance of the said type of Services. Upon commencement of performance of the said type of Services, the Services Provider shall be deemed to have represented and warranted, along with the representations and warranties in Section 5.0(a) above, that the Services Provider has visited and examined the site at which the said type of Services are to be performed and that the Services Provider has satisfied itself as to the form and nature of the site, the quantities and nature of the Services to be performed, the labour conditions existing in the area for the Services involved, facilities present on site, access to the site, the seasonal conditions limiting access to the site, the materials necessary for the performance of the Services, and any restrictions or barriers present at the site that would impact the performance of the Services and which the Services Provider was able to reasonably detect upon examination of the site.

(b) **Compliance with Standards, Specifications and Applicable Law:** The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled document entitled "Security Policy" (SP 1686 R1) dated December 2016 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with all statutes, regulations, by-laws, standards and codes as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

The Services Provider shall also comply with the General Standards and Specifications set out in Schedule "A" attached hereto and the service levels identified in Schedule "C", as may be applicable, in its performance of the Services.

The Services Provider shall be responsible for coordinating all related work activities to be performed.

(c) **Input from Services Recipient:** The Services Recipient shall cooperate and provide any required input as might be requested by the Services Provider, on a timely basis, to facilitate the performance of the Services by the Services Provider. In addition, the Services Recipient shall disclose to the Services Provider on a timely basis any information within the Services Recipient's possession or control which may reasonably affect the ability of the Services Provider to meet its obligations under this Agreement.

(d) **Constructor:** The parties acknowledge and agree that the Services Provider shall be the "Constructor" of the Services performed within the meaning of the *Occupational Health and Safety Act*, R.S.O. 1990, c. 0.1, as amended and the regulations thereunder and shall have all of the responsibilities and liabilities of a "Constructor".

(e) **Safety and Security Measures:** When any part of the Services is to be performed at the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(f) **Cleanup:** The Services Provider shall maintain the location at which the Services are performed in a tidy condition and free from the accumulation of waste products and debris, other than that caused by the Services Recipient, its contractors or their respective employees. Upon completion of the Services, the Services Provider shall remove the material, tools, machinery and equipment and waste products and debris, other than those resulting from the work of the Services Recipient, its contractors and their respective employees.

(g) **Review and Inspection of the Services:** The Services Recipient shall have access to the Services at all times. The Services Provider shall provide sufficient, safe, and proper facilities at all times for the review of the Services by the Services Recipient. The Services Recipient may order any portion or portions of the Services to be examined to confirm that such work is in accordance with the requirements of this Agreement. If the work is not in accordance with the requirements of this Agreement, the Services Provider shall correct the work and pay the cost of examination and correction. If the work is in accordance with the requirements of this Agreement, the Services Recipient shall pay the cost of examination and restoration. No payment by the Services Recipient shall constitute an acceptance of any portion of the Services which are not in accordance with the requirements of this Agreement.

(h) **Defective Services:** The Services Provider shall promptly remove from the site at which the Services have been performed and replace or re-execute defective work that has been rejected by the Services Recipient as failing to conform to this Agreement whether or not the defective work has been incorporated in the Services and whether or not the defect is the result of poor workmanship, use of defective products, or damage through carelessness or other act or omission of the Services Provider. The Services Provider shall promptly make good other contractors' work destroyed or damaged by such removals or replacements at the Services Provider's expense. If, in the reasonable opinion of the Services Recipient it is not expedient to correct defective work or work not performed as provided in this Agreement, the Services Recipient may deduct from the amount otherwise due to the Services Provider the difference in value between the work as performed and that called for by this Agreement. If the Services Provider and Services Recipient do not agree on the difference in value, they shall follow the dispute resolution procedures outlined in Section 8.0 herein.

(i) **Meetings:** The parties agree to meet quarterly after the Effective Date to review performance, quality and timeliness of the Services provided by the Services Provider.

(j) **Emergency Priority:** Upon determination by the Services Recipient that the Services Recipient is in an emergency situation, the Services Provider shall give first priority to responding to the said emergency, in priority over any emergency response commitments that the Services Provider may have to a third party.

## 7.0 CHANGES TO SERVICES

Either party may request a change to the scope of work including work already in progress in accordance with this Section.

If either party desires a change in the work described in the Services, it shall complete and submit to the other party, a Change Notification Form (the "CNF") in the form attached hereto as Schedule "B". The CNF shall identify the reasons and impact (cost and schedule) of the change. The other party shall respond to the CNF no later than 10 business days after receipt thereof. In the event that the parties agree with the change in the scope of work, price and/or time for completion, the parties shall execute the CNF and the executed CNF shall be attached to this Agreement.

In the event that the parties agree on the change in the scope of work but do not agree on a revised price for the changed scope of work, the price shall be fixed on a time and materials basis in accordance with the Services Provider's 2017-2018 hourly rates as may be amended pursuant to this Agreement and the CNF shall be executed by the parties accordingly. The Services Provider shall provide the Services Recipient with an invoice for the said changed scope of work that is payable on a time and materials basis and the invoice shall include a description of the work performed, a breakdown of the number of hours worked and applicable hourly rates. The Services Provider shall also provide to the Services Recipient such other information and supporting documentation as the Services Recipient may reasonably require. Such invoices, information and supporting documentation shall at all reasonable times be open to audit, inspection and copying by the Services Recipient and shall be preserved and kept available by the Services Provider for audit by the Services Recipient until the expiration of two years from the completion date of the changed scope of work.

The Services Provider shall not be obligated to carry out any change in the scope of work and the Services Recipient shall not be obligated to pay for any change in the scope of work unless and until the relevant CNF has been executed.

## 8.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a Director from each party (collectively "Dispute"), other than a Dispute regarding any change to the scope of work activities processed under Section 7.0 above, shall be settled in accordance with this Section. The aggrieved party shall send the other party written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. A director-level employee from each party (as chosen by each party respectively) shall confer in an effort to resolve the Dispute. If the director-level employees are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the parties shall submit the Dispute in writing to the President of Hydro One Limited for resolution.

## 9.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) **Confidentiality**: Each party (the "Receiving Party") shall maintain in strict confidence all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from the other party (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal, financial or professional advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the *Personal Information Protection and Electronic Documents Act* (Canada), as they may be amended) and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "F" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 9.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;

(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;

(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;

(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by, the Receiving Party or the Receiving Party Representatives; or

(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process, including, without limitation, an order of or legal process involving a regulatory authority such as the Ontario Energy Board.

The parties acknowledge and agree that the Confidential Information shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the Confidential Information it has disclosed to the Receiving Party.

The Receiving Party agrees that it shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party, including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) **Intellectual Property:** Unless otherwise agreed, the Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to the Services Recipient by the Services Provider in accordance with this Agreement and, subject to applicable legislation, and notwithstanding clause 9.0(a) above, the Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

(c) **Survival of Obligations:** The obligations in this Section 9.0 shall forever survive the termination or expiration of this Agreement.

## 10.0 INSURANCE

The Services Provider shall maintain in full force and effect during the term of this Agreement and with financially responsible insurance carriers, the following insurance coverage and the insurance coverage specified in Schedule "E" attached hereto as may be applicable for any and all Services:

(i) Workers Compensation as required by the Ontario *Workplace Safety and Insurance Act, 1997,* S.O. 1997, c.16, Schedule A, as amended or similar applicable legislation covering all persons employed by the Services Provider for the Services performed under this Agreement. For U.S. employees, appropriate State Workers Compensation must be carried including Employer's Liability for a minimum limit of $5,000,000 U.S., with a Foreign Coverage Endorsement and, to the extent applicable, Jones Act and U.S. Longshoreman's and Harbor Workers coverage and FELA. To achieve the desired limit, umbrella or excess liability insurance may be used. A waiver of subrogation shall be provided by the insurers to the Services Recipient.

(ii) Automobile Liability Insurance, covering all licensed motor vehicles owned, rented or leased and used in connection with the Services to be performed by the Services Provider under this Agreement covering Bodily Injury and Property Damage Liability to a combined inclusive minimum limit of $5,000,000 and mandatory Accident Benefits. To achieve the desired limit, umbrella or excess liability insurance may be used.

(iii) Commercial General and Excess Liability Insurance with limits of $5,000,000 inclusive for both bodily injury, including death, personal injury and damage to property, including loss of use thereof, for each occurrence. To achieve the desired limit, umbrella or excess liability insurance may be used. This coverage shall specifically include, but not be limited to, the following:

a. Blanket Contractual Liability;
b. Damage to property of the Owner including loss of use thereof;
c. Pollution Liability coverage on at least a Sudden and Accidental basis;
d. Products & Completed Operations to be continuously maintained through the operational liability insurance.
e. Employer's Liability;
f. Non-Owned Automobile Liability; and
g. Broad Form Property Damage

Prior to the commencement of the performance of the Services under this Agreement, the Services Provider shall provide to the Services Recipient's representative and address noted immediately below, evidence of the minimum coverages required under this Section 10.0 in the form attached hereto as Schedule "D", noting the policy number and term and executed by a duly authorized representative of their respective insurers.

**Manager, Risk and Insurance, Hydro One Networks Inc. 483 Bay Street, South Tower TCT 07, Toronto, Ontario M5G 2P5**

With the exception of subparagraph (ii) above, all insurance coverages noted above shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by the Services Recipient.

The Services Recipient shall be included as a Named Insured subject to the Sole Agent provision under coverages noted in subparagraph (iii) above, but only to the extent to which the Services

Provider is liable to the Services Recipient for breach of its obligations under this Agreement. In addition, the parties acknowledge and agree that the insurance coverages noted in subparagraph (iii) above shall contain a cross liability clause and a severability of interests clause.

The parties further acknowledge and agree that the Insurance coverage described in this Section and provided for the Services Provider shall not be invalidated by actions or inactions of others.

## 11.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Agreement and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, neither party shall be liable for any special, indirect or consequential damages or for economic loss, incurred by the other or by any third party claiming through or under the other.

The foregoing paragraph shall forever survive the termination or expiration of this Agreement.

## 12.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

**HYDRO ONE REMOTE COMMUNITIES INC.**
483 Bay St.
North Tower, 12th Floor
Toronto, Ontario
M5G 2P5
Attention: Una O'Reilly
Telephone: (416) 345-6698
Telecopier: (416) 345-6356

**HYDRO ONE NETWORKS INC.**
483 Bay St.
South Tower, 7th Floor
Toronto, Ontario
M5G 2P5
Attention: Scot Hutchinson
Telephone: (416) 345-5569
Telecopier: (416) 345-6833

All correspondence, reports, documents and/or other communication concerning this Agreement, the Schedules attached hereto or any of the Services shall be directed to the attention of the authorized representatives noted above. Any notice permitted or required to be given hereunder shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

## 13.0 FORCE MAJEURE

Except for the payment of any monies required hereunder, neither party shall be deemed to be in default of this Agreement where the failure to perform or the delay in performing any obligation is due to a cause beyond its reasonable control, including, but not limited to, an act of God, act of any federal, provincial, municipal or government action, or order of court or administrative or regulatory authority, civil commotion, strikes, lockouts and other labour disputes, fires, floods, sabotage, earthquakes, storms, ice storms and epidemics. As soon as a party anticipates that a force majeure event may occur which will delay or prevent it from performing any of its obligations under this Agreement, it shall promptly notify the other party and shall exercise all reasonable efforts to mitigate or limit the effect on the other party.

Once a party becomes subject to such an event of force majeure, it shall promptly notify the other party of its inability to perform, or of any delay in performing, due to an event of force majeure and shall provide an estimate, as soon as practicable, as to when the obligation will be performed. The party subject to the force majeure event shall also continue to furnish timely reports to the other party with respect to the force majeure event during the continuation of the said event and the said party shall exercise all reasonable efforts to mitigate or limit damages to the other party. The party subject to the force majeure event shall use its best efforts to continue to perform its obligations under this Agreement, as the case may be, and to correct or cure the event or condition excusing performance and when the said party is able to resume performance of its obligations thereunder, it shall give the other party written notice to that effect and shall promptly resume performance thereunder. The time for performing the obligation shall be extended for a period equal to the time during which the party was subject to the event of force majeure. The parties shall explore all reasonable avenues available to avoid or resolve events of force majeure in the shortest time possible.

Notwithstanding the two preceding paragraphs, the settlement of any strike, lockout, restrictive work practice or other labour disturbance constituting a force majeure event shall be within the sole discretion of the party involved in such strike, lockout, restrictive work practice or other labour disturbance and nothing in the two preceding paragraphs shall require the said party to mitigate or alleviate the effects of such strike, lockout, restrictive work practice or other labour disturbance.

## 14.0 ASSIGNMENT

Neither this Agreement nor any the rights and obligations hereunder may be assigned by either party hereto without the prior written consent of the other, which consent shall not be unreasonably withheld; provided, however, that a party may assign this Agreement or any rights, remedies or liabilities to any of its affiliates (as this term is defined in the Ontario *Business Corporations Act*, as amended) without the need for prior consent, in which case the assignor shall provide the other party with written notice of the assignment within 30 days after the effective date thereof. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.



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## 15.0 AMENDMENTS

Any amendment, modification or supplement to this Agreement shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement. Notwithstanding the foregoing, the parties acknowledge and agree that the Services Recipient shall be entitled to unilaterally change the General Standards and Specifications attached hereto as Schedule "A" provided however that the parties shall negotiate in good faith the effect of any such changes to the scope of work, time for completion of the said scope of work and the price therefor, in accordance with the process outlined in Section 7.0 above.

## 16.0 ENTIRE AGREEMENT

This Agreement, together with Schedules "A", "B", "C", "D", "E" and "F" attached hereto, represents the entire agreement between the parties hereto respecting the subject matter hereto and supersedes all prior agreements, understandings, discussions, negotiations, representations and correspondence made by or between them respecting the subject matter hereto.

## 17.0 CONFLICTS

In the event of any conflict between this Agreement and Schedules "A", "B", "C", "D", "E" and "F", the provisions of the former shall prevail. In the event of any conflict amongst the Schedules, then the Schedules shall take precedence in the following order: (i) Schedule "C", (ii) Schedule "D"; (iii) Schedule "B"; (iv) Schedule "A"; (v) Schedule "E" and (vi) Schedule "F".

## 18.0 GOVERNING LAW

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

## 19.0 SCHEDULES

Schedules "A", "B", "C", "D", "E" and "F" attached hereto are to be read with and form part of this Agreement.

## 20.0 RELATIONSHIP OF PARTIES

Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not present themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either party which could establish any apparent relationship of agency, employment, joint venture or partnership and neither party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other party to any other person nor with respect to any other action of the other party.

## 21.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

**IN WITNESS THEREOF** the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

| HYDRO ONE REMOTE COMMUNITIES INC. | HYDRO ONE NETWORKS INC. |
|---|---|
| Name: KEVIN MUNN | Name: |
| Title: ACTING DIRECTOR | Title: |
| I have authority to bind the corporation. | I have authority to bind the corporation. |



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## 21.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

**IN WITNESS THEREOF** the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

| HYDRO ONE REMOTE COMMUNITIES INC. | HYDRO ONE NETWORKS INC. |
| --- | --- |
| ______________________________ | B.Bowness |
| Name: | Name: BRAD BOWNESS |
| Title: | Title: VP - DISTRIBUTION |
| I have authority to bind the corporation. | I have authority to bind the corporation. |

**<u>Schedule "A"</u>**

## GENERAL STANDARDS AND SPECIFICATIONS

hydro one

**REVISION HISTORY**

| Date | Revision No. | Modification | Comments |
|---|---|---|---|
| | | | |
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| | | | |
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## GSS #1 USED, REUSABLE AND WASTE MATERIALS

### 1.1 DEFINITIONS

#### 1.1.1 Reusable Material

Where practical, the Services Provider shall reuse and re-deploy all material that is removed from service, provided such material is still in good operating condition and satisfies the criteria indicated in this GSS #1.

#### 1.1.2 Waste Material

All other material that is removed from service will be considered to be waste material.

#### 1.1.3 Recycling

Recycling means using waste material for purposes other than those for which the material was originally intended: it does not include destruction (such as incineration or burning as a supplementary fuel) or use as land fill.

### 1.2 EXPECTATIONS

Costs for the management of used material that is associated with capital projects, including the disposition of such material for re-deployment, re-use and/or disposal, shall be identified in Schedule "C", where applicable (e.g. the cost to pickup, transport and dispose of PCB fluids and contaminated waste).

The Services Provider shall handle all reusable material removed from service in a manner that is consistent with Schedule "C" (where identified) and in accordance with applicable legislation, statutes, by-laws, codes, guidelines, regulations, and Hydro One procedures. Such material shall be stored in a safe and secure manner to minimize any risk of physical damage and/or of environmental or health and safety impacts associated with such damage, pending re-deployment or shipment to storage.

The Services Provider shall manage and dispose of waste material in a manner that is consistent with Schedule "C" (where identified) and in accordance with applicable legislation, statutes, by-laws, codes, guidelines, regulations, and Hydro One procedures. Preference will be given, where practical, to disposal options that maximize the potential for recycling.

### 1.3 CRITERIA FOR USED MATERIALS

| Material | Criteria and Action |
|---|---|
| Poles | • Distribution poles shall be less than 16 years old<br>• Transmission poles shall be less than 12 year old<br>• Penta-treated poles shall not be reused<br>• All wood poles no longer required by the Services Recipient shall be returned to the appropriate service/operations centre.<br>• All wood poles no longer required by the Services Recipient shall be disposed of appropriately. |

| Material | Criteria and Action |
|---|---|
| Pole-Mounted Transformers | • Must be no older than 1974<br>• If less than 200ppm PCB, a pole-mounted transformer shall be drained, refilled and re-tested after 2 years<br>• If bushings are side-mounted they shall be recycled<br>• Pole-Mounted Transformers shall be visually inspected (remove cover). If the inspection indicates no damage to the coil, they shall be returned for repair<br>• If a transformer fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste |
| Pad-mount Transformers | • All such transformers shall be returned for repair<br>• If less than 200ppm PCB, a pad-mounted transformer shall be drained, refilled and re-tested after 2 years<br>• Pad-mounted transformers shall be visually inspected. If the inspection indicates no damage to the coil, they shall be returned for repair<br>• If a transformer fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste |
| Line Voltage Regulators | • This includes any 50A line regulator retained for parts; all others shall be returned for repair<br>• If less than 200ppm PCB, line voltage regulators shall be drained, refilled and re-tested after 2 years<br>• Line voltage regulators shall be visually inspected (remove cover). If the inspection indicates no damage to the coil, they shall be returned for repair<br>• If a regulators fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste |
| Oil Circuit Reclosers | • If less than 200ppm PCB, the reclosers shall be drained, refilled, and re-tested after 2 years<br>• Reclosers shall be visually inspected (remove cover). If the inspection indicates that there is no damage, they shall be returned for repair<br>• If a recloser fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste |
| Metering Transformers / Units | • If less than 200ppm PCB, the units shall be drained, refilled and re-tested after 2 years<br>• The units shall be visually inspected (remove cover). If the inspection indicates no damage to the coil, it shall be returned for repair<br>• If a unit fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste |
| Capacitors | • No PCB or Dielektrol I- or II-filled capacitors shall be reused<br>• Capacitors shall not have an unknown PCB content unless permission is obtained from the Services Recipient. Some capacitors manufactured before January 1981 may contain PCB over 50 ppm. |
| Primary Conductors | • If less than 3/0, primary conductors shall be reused for extensions where the main line is of the same size<br>• Before reusing, #2 shall be inspected for deterioration in the core<br>• All other conductors shall be reused |
| Secondary Conductors/ Underground Cable | • Secondary Conductors/Underground Cables shall be reused if they pass an asset condition test<br>• The units must contain no splices (in the underground cable) that test greater than 50 mg/kg PCB. In addition, end sections must not have come from terminations that test greater than 50 mg/kg PDB.<br>• All secondary conductors shall be reused<br>• No underground cables shall be reused if they are more than 10 years old |
| Submarine Cable | • No submarine cable shall be used if it is more than 5 years old |

| Material | Criteria and Action |
|---|---|
| Insulators | • All single piece porcelain pin insulators shall be reused (not other porcelain insulators): the intent is to replace insulators with silicone (polymer) types on 115 kv and 230 kv, where practical<br>• Epac insulators shall not be reused<br>• Cob porcelain post insulators shall not be reused |
| Cross-arms | ***Distribution:***<br>• Cross-arms shall be reused if no apparent cracking or excessive aging is evident |
| | ***Transmission:***<br>• All wooden cross-arms shall be removed and disposed<br>• All steel cross-arms shall be reused |
| Spool Bolts | • All spool bolts shall be reused |
| Switches | ***Distribution:***<br>• No Kearney switches nor rigid polymeric insulator-type switches shall be reused |
| | ***Transmission:***<br>• All shall be 115 kV & 230 kV in-line polymeric switches<br>• Only those switches that have tested satisfactorily shall be reused |
| Insulating Oil | • All insulating oil is required to meet specification for Voltesso 35 Category "B" oil OR have the potential to be upgraded to meet this specification<br>• Insulating oil must contain less than 50 mg/kg PCB by laboratory test |

## 1.4 FINANCIAL TREATMENT OF USED MATERIAL

The Services Provider shall report all units removed from service. When used materials are reused for capital or maintenance work, the materials shall be charged to the work as if the material was new.

## 1.5 INFORMATION REQUIREMENTS

The Services Provider shall record and report the following information to the Services Recipient according to a schedule specified in the description of Services in Schedule "C" to the Agreement.

- Transformer Units by MVA/kVA and voltage, whether installed, salvaged or disposed as waste (new or used material)
- Regulator/Rabbit Units by kVA and voltage, whether installed, salvaged or disposed as waste (new or used material)
- Recloser Units by voltage and interrupting rating
- Switches by manufacturer type and voltage rating
- Capacitor Units by total MVA/kVAR, including voltage, number of phases and control type, whether installed, salvaged or disposed as waste (new or used material)
- Transmission line structures and distribution pole units by type (steel or wood pole), height, age, ownership (Hydro/Bell Canada/MEU), Bell Canada I.D. (exchange, route and pole number), structure number
- Conductor Units by size, type and length, whether installed, salvaged or disposed as waste (new or used material)
- Cable size, type, length and voltage, whether installed, salvaged or disposed as waste (new or used material)
- Record or retained material, including volumes scrapped, reused or repaired and reused.

(1) Note: The information listed above is required for accounting purposes at the plant.

## 1.6 WASTE MATERIAL

For waste material that is classified as either hazardous or as liquid industrial, the Services Provider shall follow specific requirements. These requirements are detailed in the appropriate legislation (e.g., *Environmental Protection Act, Occupational Health & Safety Act*) and internal policies/standards/procedures (e.g., Waste Management Manual). Records of hazardous waste volumes shipped to disposal shall be reported to the Services Recipient and such records shall be maintained according to established records management. All hazardous waste material shall be handled and managed with due regard for worker and public health and safety.

## GSS #2 ENVIRONMENT, HEALTH & SAFETY REQUIREMENTS

### 2.1 GENERAL STATEMENT OF COMPLIANCE AND REQUIREMENTS

The Services Recipient expects to receive the same level of compliance, where applicable, for services provided under the Agreement. As a minimum, the Services Provider shall comply with the following:

- Federal and Provincial legislation;
- Municipal by-laws;
- The Services Recipient's Safety Rules and Policies;
- All legacy Ontario Hydro policies, procedures and standards still applicable to the Services Recipient;
- Policies approved by the Services Recipient's Board of Directors;
- The Services Recipient's Environment, Health & Safety Management policies, procedures and associated standards; and
- The Services Recipient's Policy for Health & Safety Incident Management.

### 2.2 ENVIRONMENTAL REQUIREMENTS

#### 2.2.1 General Requirements for Management of the Environment

For managing the environment, the Services Provider shall abide by the following:

a) The Services Provider shall design, construct, operate, maintain and decommission the Services Recipient's facilities in accordance with standards to be developed by the Services Recipient and made available to the Services Provider.

b) The Services Provider shall perform all work on behalf of the Services Recipient in a manner that is consistent with the principles of an environmental management system including, as a minimum:
   - Assigning and communicating individual accountability and responsibility for the environment;
   - Engaging qualified employees and agents (i.e. with respect to knowledge, training and experience to perform the work assigned) to perform the work;
   - Having emergency preparedness and response capability suitable to the range of issues that could be encountered during the course of the work detailed in Schedule "C" to the Agreement;
   - Inspecting, maintaining and monitoring equipment, facilities and employees during the course of providing the Services;
   - Reporting environmental incidents, performing incident investigations and implementing corrective actions in response to an incident; and
   - Periodically reviewing environmental management processes and making improvements, as necessary.

c) The Services Provider shall consider the environmental implications of all work and integrate environmental considerations into its plans for all work that could have an adverse effect on the environment.

d) In performing the services, the Services Provider shall:
   - Use materials, products and equipment that are government-approved, industry-accepted and sustainable (i.e., from environmental, economical, social perspectives). The Services provider shall give preference, where practical, to materials and products that have low toxicity and do not contain substances that are included on Schedule 1 (List of Toxic Substances) of the *Canadian Environmental Protection Act* or on the Priority Substances Lists 1 and 2.
   - Maximize the efficient use of resources;
   - Be energy efficient; and
   - Conserve heritage resources.

e) The Services Provider shall, when included in the project scope, prepare and implement project-specific environmental specifications when the prevention or mitigation of predicted environmental impacts can only be assured by the application of a specific damage prevention or mitigation approach. Such environmental management specifications will be consistent with applicable standards.

f) The Services Provider shall prepare and provide to the Services Recipient, project-specific, As-Constructed Reports for all projects that require any one or more of the following, where the Services Recipient and the Services Provider shall mutually determine which environmental authorities or industry or legislative standards shall be used in developing such reports:

- Environmental permits;
- Environmental considerations or special commitments;
- Access agreements, construction property agreements and special conditions that contain a record of the final environmental state of the project;
- Documentation of significant environmental situations or activities; and
- Property rights summaries.

g) The Services Provider shall provide to the Services Recipient, the records identified in (b), (e) and (f).

### 2.2.2 Environmental Incident Management

The Services Provider shall consistently respond and report environmental incidents and ensure that all such incidents involving Distribution or Transmission assets and lands are managed effectively. Included as "environmental incidents" are:

- Vandalism, natural events (such as lightning, ice, and wind) and animal activity;
- Accidental or inadvertent public contact with electrical system assets or equipment (such as motor vehicle accidents, ladders into lines);
- Mechanical/electrical failure for no apparent reason or unknown cause;
- Asset management standards that are subsequently shown to have contributed to the incident; and
- Operation or maintenance activities in accordance with accepted standards that would not normally be expected to cause leaking, equipment failure or malfunction.

The Services Provider shall document all environmental incidents (such as spills and fires) involving the Services Recipient's assets and/or lands (owned or easement) (e.g., complete a Hydro One Environmental Incident Report). The Services provider shall enter this information into the Web Environmental Incident Collector (WebEIC) database and/or any other similar database, as directed by the Services Recipient.

The Services Provider shall consistently respond to, and report, environmental incidents. The Services Provider shall also ensure that all environmental incidents involving the Services Recipient's assets and land are managed effectively.

## 2.3 HEALTH & SAFETY

### 2.3.1 Potential Hazards

There are two significant hazards associated with work on the Services Recipient's assets:

- Hazards inherent to working in proximity to electrical equipment; and
- Hazards inherent to working at heights.

The Services Provider may also work in buildings or at sites where hazardous substances are present. Inventories and assessments of potentially hazardous or hazardous substances have been completed for the majority of the Services Recipient's sites; they are available to the Services Provider on request. All requests should be made locally.

The Services Provider shall manage all hazards associated with all Services with the Services Recipient.

### 2.3.2 General Requirements for the Management of Health & Safety

The Services Provider shall perform all work on behalf of the Services Recipient in a manner that is consistent with the principles of a health and safety management system including, as a minimum:

(a) Assigning and communicating individual accountability and responsibility for health and safety;
(b) Engaging qualified employees and agents (i.e. with respect to knowledge, training and experience to perform the work assigned) to perform the work;
(c) Having emergency preparedness and response capability suitable to the range of issues that could be encountered during the course of the work detailed in Schedule "C" to the Agreement;
(d) Inspecting, maintaining and monitoring equipment, facilities and employees during the course of providing the Services;

(e) Reporting safety events, performing event investigations and implementing corrective actions in response to an event;

(f) Periodically reviewing health and safety management processes periodically and making improvements, as necessary; and

(g) Submitting the records identified in (e) and (f) to the Services Recipient.

The Services Provider shall ensure the protection of the public in the performance of all work for the Services Recipient.

### 2.3.3 Health & Safety Event Management

The Services Provider shall consistently respond and report all health and safety events involving the Services Recipient staff and/or members to the Services Recipient. Included as health and safety events are:

- Vandalism, natural events (such as lightning, ice, and wind) and animal activity;
- Accidental or inadvertent public contact with electrical system assets or equipment (such as motor vehicle accidents, ladders into lines);
- Mechanical/electrical failure for no apparent reason or unknown cause;
- Asset management standards that are subsequently shown to have contributed to the event; and
- Operation or maintenance activities in accordance with accepted standards that would not normally be expected to cause leaking, equipment failure or malfunction.

## Schedule "B"

**CHANGE NOTIFICATION FORM (No. xxx)**

**Date issued: xx-xxx-xx**

| | | |
|---|---|---|
| **Services Description** | | |
| **Project ID** | **Services Recipient** | **Services Provider** |
| **Scope Change** | | |
| **Reason for Change** | | |
| **Schedule/Delivery Impact** | | |
| **Impact on Price** | **Old Price:**<br>**New Price:** | |
| **Approvals** | **Hydro One Networks Inc.** | **Hydro One Remote Communities Inc.** |
| **Effective Date of Change:** | | |
| **Proposed By:** | | |
| **Date:** | | |
| **Reviewed By:** | | |
| **Date:** | | |
| **Approved by:** | (Authorized Signatory) | (Authorized Signatory) |
| **Date:** | | |

**Schedule "C"**

**Description of Services**

**FORESTRY SERVICES:**

**A. Description of Services:**

The Services Provider shall provide the Services Recipient with the following forestry services:

1. Upon the Services Recipient's request, perform condition assessments of the Services Recipient's distribution systems, and prepare a proposed multi-year forestry maintenance cycle for the Services Recipient.

2. Upon the Services Recipient's request, perform condition assessments of the Services Recipient's assets, and prepare cost estimates depicting at a minimum: labour hours and type (Technician, Supervisory, Maintainer, HH, etc.), TWE rates and requirements, material costs, board and lodging expenses, transportation costs excluding air charters, and applicable sundries in sufficient detail necessary for work scheduling and business planning purposes. As well, the amount of joint use right of way and associated clearing costs shall be identified by the Services Provider within the estimates.

3. Site monitoring of line clearing and/or brush control performed by third party contractors retained by the Services Recipient for servicing its rights of way in First Nation Communities as identified by the Services Recipient's representative. As required, the Services Provider shall clear lines and remove brush within the limits of approach to make it safe for First Nation Community contractors to clear lines and control brush outside the limits of approach.

4. Perform line-clearing in all communities within the Services Recipient's designated territory and brush control on all assets located on provincial land as identified by the Services Recipient. As well, from time to time as requested by the Services Recipient, the Services Provider will perform brush control activities on First Nation lands when the First Nation is unable to unwilling to perform the task to meet applicable standards.

5. Perform brush control measures including herbicide application where applicable in all station yards within the Services Recipient's territory.

6. Assist with the development of the line clearing and brush control specifications and standards necessary for negotiations with third party contractors and First Nations Administration.

7. Assist in providing notification of forestry services to communities and attaining necessary permissions from property owners or custodians.

8. Obtain various work permits such as cutting rights and stumpage fees on Crown Land or from companies with assigned cutting rights, fuel wood and stream crossing permits from the Ministry of Natural Resources, or transportation/crossing arrangements with the Canadian National Railway or Canadian Pacific Railway for the performance of the forestry services.

9. Provide forestry support for emergency line clearing and trouble calls.

10. Provide forestry support for line clearing and brush control as required for work driven by extensions, connections, betterments and upgrades to distribution facilities.

11. Provide documentation and support to enable the Services Recipient to obtain Purchase Service Agreements (PSA) with the Power Workers Union (PWU) for line clearing in First Nation communities, as well as, necessary sole source and procurement documentation.

12. Prepare and provide detail cost estimates of identified planned work to the Services Recipient by April 15, 2017 in order to facilitate business planning for the following year as may be needed. The Services Recipient shall identify the work to be estimated by March 1, 2017. Other estimates that may be required throughout the year and will be prepared and provided 15 days after the request is received by Forestry Services Scheduling.

13. The Services Provider shall prepare and provide necessary PSA and procurement documentation for First Nation brushing contracts by April 15, 2017. The Services Recipient will be responsible for managing and completing PSA negotiations with the PWU and approve procurement documents as it deems necessary.

14. The Services Provider shall complete 100% of the annual planned line clearing and brush control operations by December 15' 2017. The details of the annual plan will be discussed at a meeting between the Services Recipient's Customer Service Manager or delegate and the Services Provider's Forestry Superintendent - Northern Zone or Territory Manager delegate and shall be held before the end of February, 2017 where the parties will confirm activities and expectations for the year.

## B. Price and Terms of Payment:

The Services Recipient shall pay the Services Provider for the forestry services on a time and materials basis in accordance with the wage schedules of the Services Provider.

The above fees payable excludes all airfares and lodging and contractual obligations as required under the collective agreement for the Services Provider's costs while working at the Services Recipient's facilities, which shall be paid directly by the Services Recipient. The Services Recipient will arrange and pay for the scheduling of charter flights to the Services Recipient's sites.

## C. Service Levels:

The Services Provider shall report the following information in writing to the Services Recipient by December 15, 2017:

- Kilometers of line controlled / treated in each community
- Number of helicopter landing sites cleared
- Total actual cost of the forestry services in each community
- Instances of customer objection to use of herbicides and/or treatment of vegetation by any method; such customer disputes shall be resolved by the Services Recipient if resolution could not be attained through the Services Provider's regular procedures
- Detailed work completion reports of line clearing and brush control in each community upon completion of project.

## METERING SERVICES:

### A. Description of Services

The Services Provider shall provide the Services Recipient with the following metering services:

- manage the Services Recipient's annual Meter Reverification and Sample Program : issuing (Change Meter Orders – CMOs) work orders to the Services Recipient's field forces for meter change-outs of recalled (due meters), seal expired (overdue), sample and failed meters;
- verify/reverify and seal meters to meet the Services Recipient's field demand for meter change-outs;
- manage a physical meter inventory by maintaining adequate stock of metering equipment to meet the needs for annual meter reverification, new services, service upgrades and replacement of failed or defective/damaged meters;
- acquire / provide data to the Services Recipient as required by the Services Recipient to resolve meter disputes and customer complaints, including, as required, metering documentation and documentation about hardware;
- manage meter requirements for change-outs of reported damaged or defective meters (i.e. defective replacements) and disputed meters. The Services Provider shall issue meter equipment (pending equipment availability) within 7 working days of a field request therefor from the Services Recipient;
- audit/review physical meter and instrument transformer records in compliance with the requirements in the federal *Electricity and Gas Inspection Act* as amended;
- develop metering specifications/standards and provide engineering support to the Services Recipient;
- provide access to training and conferences (including, where appropriate, training provided by third parties (for e.g. . the Electricity Distributors Association (formerly, the Municipal Electric Association) and training provided by the Services Provider's Training and Development Services staff) ;
- liaise with Measurement Canada on behalf of the Services Recipient including with respect to audit and metering installation reporting.

The Services Provider shall provide the Services Recipient with a written report by no later than December 15, 2017 wherein it shall specify the cost and accomplishments of the metering services provided by its personnel for the said year.

### B. Price and Terms of Payment:

The Services Recipient shall pay to the Services Provider for these metering services on a time and materials basis. The payment terms are as specified in the Agreement.

### C. Service Levels:

All metering services will be provided by the Services Provider in accordance with the requirements in ISO 9001:2008 as revised by ISO 9001:2015.

## WORK METHODS AND TRAINING SERVICES:

### A. Description of Services:

The Services Provider shall provide the Services Recipient, as required by the Services Recipient, with the following services related to specific job procedures outlining sequence, tools, resources, safety precautions, and hazards relating to job tasks (collectively, the "Work Methods") and trades/technical training support for distribution lines, customer service and station maintenance trades in accordance with the specific terms and conditions noted therein:

**1. Training Delivery**

- The Services Provider will provide requested trades training for the Services Recipient.
- The Services Recipient will provide the names of all employees working for the Services Recipient on a continual basis (i.e. new employees/apprentices) to the Services Provider.
- The Services Provider shall schedule the training in such manner so as to meet the Services Recipient's reasonable needs. In order for the Services Provider to meet these needs, the Services Recipient shall submit a "Request for Training" form 30 days in advance of the training requested, which form may be amended from time to time by the Services Provider. The "Request for Training" form is posted, and can be accessed, electronically at the Hydro One Plugin Website>HSE>Training>Forms (http://hydronet.hydroone.com/Pages/default.aspx).
- The Services Recipient shall determine and notify the Services Provider as to whether or not training will be delivered in a centralized or decentralized manner.
- The Services Recipient will also notify the Services Provider with as much time as possible in the event there is a need for Training course cancellation, but in any event no less than 10 Business Days' prior written notice. The Services Recipient acknowledges and agrees that if it does not provide the Services Provider with a minimum 10 Business Days prior written notification of training course cancellation, the Services Recipient will bear all costs that may have been incurred by the Services Provider for training development, scheduling, travel, and accommodations related to said training course.

The Services Provider and the Services Recipient shall comply with the following accountability matrix:

| **Accountabilities Matrix** | |
|---|---|
| **Task** | **Accountability** |
| Approval of Course Content | Services Recipient |
| Course Participants | Services Recipient |
| Course Instructors | Services Provider |
| Course Scheduling | Services Provider |
| Development of Course Material | Services Provider |
| Quarterly Report of all training activities to Services Recipient | Services Provider |

**2. Records Maintenance**

- The Services Provider shall input all of the Services Recipient's training data into the Services Provider's centralized database within ***(10) ten*** Business Days after the Services Provider's receipt from the Services Recipient of the completed "Training Record Input Form", which form may be amended from time to time by the Services Provider. The "Training Record Input Form" is posted, and can be accessed, electronically at the Hydro One Plugin Website>HSE>Training>Forms (http://hydronet.hydroone.com/Pages/default.aspx).

- The training record maintained by the Services Provider will include all legislated, Corporate-mandated and trade specific training. Other topics will be included at the request of the Services Recipient.
- All training records/information shall be accessible via the Hydro One Learning Management System (view only – HOLMs on the Hydro One Plugin Website - (http://hydronet.hydroone.com/Pages/default.aspx) by the Services Recipient.

**3. Training Material Development**

- The Services Recipient will identify to the Services Provider the skill sets required, including all mandatory-training requirements. The Services Recipient shall inform the Services Provider requests to develop new training material by completing the "WM&T Creation of New Projects" Form, which form may be amended from time to time by the Services Provider. The "WM&T Creation of New Projects" Form is posted, and can be accessed, electronically at the Hydro One Plugin Website>HODS>SP-0699 (http://hydronet.hydroone.com/Pages/default.aspx).
- The Services Provider will produce and maintain all course materials as directed by the Services Recipient, including a list of Subject Matter Experts participating and/or completing the project.
- The modification of training packages will be developed by the Services Provider within a timeframe agreed to by both parties, after the Services Provider's receipt of signed terms of reference from the Services Recipient. The Services Provider shall ensure that the modifications shall include such items as new equipment, legislative changes, performance requirements and new procedures as requested by the Services Recipient.

**4. Communication**

- The Services Recipient's training contact will be identified to the Services Provider by no later than October 30, 2017 and will speak with the Services Provider's representative identified in the body of the Agreement on a quarterly basis to review the Services Provider's performance of the work methods and training services as required by the Services Recipient. The Agenda for these quarterly meetings will be developed by the Services Recipient and forwarded to the Services Provider.
- A course catalogue and availability of training courses for the coming year will be provided by the Services Provider to the Services Recipient on an ongoing basis. This is currently available to the Services Recipient through HOLMs.

**5. Work Methods and Procedures Development**

- The Services Provider will provide assistance to the Services Recipient in the development of new Work Methods and/or procedures as required by the Services Recipient.
- The development and assessment of new work procedures/tools will be a joint effort between the parties based on a terms of reference document which shall be provided by the Services Recipient to the Services Provider with timeframes for completion established by both parties.
- The Services Provider will provide the Services Recipient with access to all work procedures and bulletins developed by the Services Provider.

### B. Price and Terms of Payment:

The Services Recipient shall pay the Services Provider for the Work Methods services on a time and materials basis in accordance with the wage schedules of the Services Provider.

In addition, the Services Recipient will pay the cost of all material, travel and per diem costs incurred by the Services Provider related to the provision of these work methods and training services. The scheduling of charter flights to the Services Recipient's sites will be arranged and paid for by the Services Recipient. The Training Specialist/officer's time includes development and scheduling and shall be paid by the Services Recipient. The Training Manager's costs, including managing these work methods and training services, shall be paid by the Services Recipient in accordance with the hours in the chart above.

### C. Service Levels:

- Training schedules/course availabilities for all required training (which are currently provided/available through the Services Provider's HOLMS database) shall be issued by the Services Provider within 90 days after the date first written above.
- The Services Provider shall provide the Services Recipient with post-course assessments of trainee accomplishment/performance to ensure employee competencies in areas trained.
- The Services Provider shall ensure that 95% of the scheduled training shall be provided to the Services Recipient prior to expiry of the term of the Agreement.

## PROVINCIAL LINES SERVICES:

### A. Description of Services:

Demand Work and Trouble Repairs:

Subject to the Services Provider's availability of personnel and resources which shall be determined by the Services Provider in its sole discretion, the Services Provider shall, in accordance with the Services Recipient's request from time to time, maintain the Services Recipient's distribution system (which distribution system supplies customers in remote communities at voltages of less than 50kV) by providing the following activities, as may be requested by the Services Recipient:

- Customer connection/disconnection to/from the primary distribution system
- Trouble Call Response, power restoration and storm damage repairs
- Line layout, estimating and staking
- Service Layouts and Collections
- Power line maintenance, construction and repair
- Distribution system operation including application of the Work Protection Code
- ADET/Metering Technician technical trouble support

For the performance of the above-referenced provincial lines services, the Services Provider shall provide:

1. subject to staff availability, short duration (six weeks or less) release of up to a maximum of 2 Regional Line Maintainers (RLMs) to cover absence/augment crew size. The Services Recipient will contact the Services Provider (Customer and Business Service Manager) as soon as practical to identify the need for all resources;

2. trouble Call Response: provide work crew(s) from appropriate geographical locations (Thunder Bay, Ear Falls, Dryden, Kenora, Timmins) in response to customer trouble calls dispatched by either the Services Recipient's First Line Manager/Union Trades Supervisor lines or the Services Provider's Supervisor on call. Trouble Calls crews shall be provided by the Services Provider on short notice and are subject to availability;

3. subject to staff availability, Customer Demand Work: Provide work crew(s) from appropriate geographical locations (Thunder Bay, Ear Falls, Dryden, Kenora, Timmins) in response to customer connection/ minor line construction requests from the Services Recipient's First Line Manager;

4. subject to staff availability, Lines Technical Work: Provide an Area Distribution Engineering Technician, (ADET)/Metering Technician, or Line Technician for short duration (six weeks or less) work assignments upon request from the Services Recipient's First Line Manager;

5. respond to requests for distribution system technical services and engineering approval(s).

Planned Work:

The Services Provider will work with the Services Recipient's First Line Manager to include in the Services Provider's plans the availability and supply of personnel and resources to meet the requirements for planned work in the Services Recipient's service territory. The Services Provider shall, in accordance with the Services Recipient's work plans respond to the Services Recipient's requests, from time to time, to maintain the Services Recipient's distribution system (which distribution system supplies customers in remote communities at voltages of less than 50kV) by providing the following activities, as may be requested by the Services Recipient:

- Line layout, estimating and staking
- Service Layouts and Collections
- Power line maintenance, construction and repair
- Sentinel light installation, repair or removal
- Distribution system operation including application of the Work Protection Code
- Meter Installation and reverification and sample meter changes
- Processing requests for railway and water crossing approvals
- Joint Use Consultation/Technical support
- Technical services in support of the Hydro One distribution line standards
- Engineering approval(s) and updates to the Distribution line standards
- MDx (Distribution system) data collection training and assistance
- Training and technical support for implementation and maintenance of ArcFM.

For the performance of the above-referenced provincial lines services, the Services Provider shall:

1. include in the Services Provider's plans, and make available, staff for short durations (6 weeks or less) release of up to a maximum of 2 RLMs to cover absence/augment crew size;

2. include in the Services Provider's plans, and make available, staff for short durations (6 weeks or less) work crew(s) from appropriate geographical locations (Thunder Bay, Ear Falls, Dryden, Kenora, Timmins) in response to customer connection/ minor line construction, MDX data collection requests from the Services Recipient's First Line Manager;

3. include in the Services Provider's plans, and make available, staff for short durations (6 weeks or less), Area Distribution Engineering Technician, (ADET)/Metering Technician and Line Technician upon request from the Services Recipient's First Line Manager;

4. respond to requests for distribution system technical services and engineering approval(s).

Supervision, Administration, Health and Safety

The Services Provider shall comply with the following supervision, administration, health and safety, and work management conditions in its performance of the provincial lines services:

1. All training, supervision and administration costs associated with staff on rotation shall be accounted for within the Services Recipient's work program. Core/mandatory training shall be scheduled within the regular work location whenever possible.

2. Whenever possible, the Services Provider will provide advice for all Lines and Technician training requirements. Also, whenever possible, the Services Provider will provide

notification for all Lines and Technician training that will be delivered at the local Hydro One Thunder Bay office. It is agreed that the Services Recipient will pay for all costs incurred by its staff to attend this training. Costs associated per Services Recipient employee will be agreed to prior to the Services Recipient employee attending the training.

3. Health and Safety incidents involving crews under the Services Provider's direct supervisory control shall be the responsibility of the Services Provider's lines operations centres.

Transport and Work Equipment (TWE) Provision

1. The Services Recipient will provide TWE at all fly-in sites for types of work, i.e. Trouble Calls, other Line work, Technician work.
2. For demand work at road access sites, trouble calls and new connects, the Services Provider will supply TWE, the cost of which will be included in the fees payable by the Services Recipient.
3. For Technician work at road access sites, the Services Provider will supply TWE and the costs of TWE will be included in the fees payable by the Services Recipient.

**B. Price and Terms of Payment:**

Except as specifically provided herein, the Services Recipient shall pay the Services Provider for the Provincial Lines Services on a time and material basis, including overtime.

The Services Recipient will pay for all costs associated with fly-in work.

Planned Work

- Time and Materials including any required overtime.
- The Services Recipient shall pay all incremental travel/overtime costs for the assignment of personnel from locations other than Thunder Bay for Lines, Technician and Customer Service personnel.
- In addition, the Services Recipient will pay the Services Provider's costs of the administration and reporting in respect of these Provincial Lines Services, material, transport and work equipment, travel and per diem costs related to the provision of these provincial line services other than trouble call response services.

## C. Service Levels:

Service Level for Demand Work:

The Services Recipient will contact the Services Provider's relevant Zone Business Manager when demand work is required. The Services Provider's Business Manager will inform the Services Recipient of staff availability within 48 hours of being contacted by the Servies Recipient. For short duration (six weeks or less) demand work requiring one staff member, the Services Recipient must provide the Services Provider with at least 4 business days' notice of a need for such work. For short duration (six weeks or less) demand work requiring four staff members, the Services Recipient must provide the Services Provider with at least two weeks' notice of a need for such work.

100% of requests shall be satisfied within 14 days' after receipt of the request

For short duration (six weeks or less) Line and Technician work – an email request will be provided by the Services Recipient to the Services Provider for all planned work assignments. Fourteen days prior written notice is required to be provided by the Services Recipient to the Services Provider for cancellation/withdrawal of staff/crews committed to short duration (six weeks or less) assignments. The Services Recipient may request personnel and resources of up to 2 RLMs and 2 Distribution Line/Metering Technicians.

Trouble Response – 24/7

Service Level for Trouble Call Response:

Subject to the immediately proceeding sentence, the Services Provider shall restore service to customer and/or community within 24 hours after receipt by the Services Provider of the Trouble Call from the Services Recipient. The Services Recipient acknowledges and agrees that during major storm events, the Services Provider's staff may not be available to meet the 24-hour response timeframe, however, staff not involved in emergency work will be dispatched immediately and other staff will be dispatched as soon as conditions allow.

Scope of Trouble Calls that will be responded to by the Services Provider:

- approximately 24-30 calls/year
- Work is mainly transformer re-fusing and switch re-fusing
- Each call is typically 3-4 hours of work and 6-8 hours of travel

For trouble repairs that are required immediately, the Services Recipient will contact the Services Provider's on-call supervisor and the Services Provider's on-call supervisor shall inform the Services Recipient of staff availability within 1 hour of being contacted by the Services Recipient.

Planned Work

The Services Recipient will contact the Services Provider's Business Manager when planned work is required. The Services Provider's Business Manager will inform the Services Recipient of staffing availability within 72 hours of being contacted by the Services Recipient. For planned work requiring more than 1 individual for periods in excess of three weeks, the Services Recipient must contact the Services Recipient at least three weeks in advance. .

The Services Provider will meet with the Services Recipient's FLM annually and include the Services Recipient's personnel and resource needs in the Services Provider's personnel and resource planning and scheduling. In order to facilitate integration of resource requirements, a meeting will be held during the first quarter of the term with the Services Provider's Zone 7 contact person where the Services Recipient will make known all major planned work for the year. Planned work not identified during this meeting will be subject to staff availability; however, efforts will be made to accommodate and may include resourcing from other parts of the Province.

The Services Recipient's contact person for work assignments is First Line Manager (FLM) Customer Service/Lines and Scheduling.

The Services Provider's contact person for work assignments in Zone 7 is the Business Manager; for other Zones, it will be the Superintendent, his delegate or scheduling group as agreed by the parties. Special requirements, scheduling conflicts and service level performance concerns will be discussed with the respective Zone Superintendent.

## SAFETY SERVICES:

### A. Description of Services:

The Services Provider shall provide the Services Recipient with following services related to safety:

**1. Incident Reporting**

The Services Provider shall assist the Services Recipient's Line Management with the proper and timely notification of safety related incidents for:

- Corporate reporting requirements
- Workplace Safety and Insurance Board
- Ministry of Labour

**2. Incident Investigation**

The Services Provider shall provide assistance/leadership for the investigation of high MRPH (Maximum Reasonable Potential for Harm) incidents and other lower incidents as requested by the Services Recipient's Line Management, the scope of which activities shall include, but not be limited to, the following:

- Prepare an initial bulletin notice of incident occurrence
- Assist with the Terms of Reference for incident investigations
- Being an investigation team member/leader
- Review/present the final report of the incident investigations to the Services Recipient's Line Management
- Assist with the development of an action plan to implement investigation recommendations

**3. Health and Safety Management**

The Services Provider shall assist the Services Recipient's Line Management with the development and maintenance of the Services Recipient's Health and Safety Activities, in support of their Environmental Health and Safety Management System (EHSMS) which may include the following:

- conduct an annual review of the Services Recipient's EHSMS, provide analysis and make recommendations for improvements;
- identify Hydro One safety requirements and provide information/advice on legal and other requirements applicable to the Services Recipient's business;
- Prepare/issue a quarterly newsletter of recent H/S legislative changes and developments affecting the Services Recipient.

**4. Compliance Reviews**

In consultation with the Services Recipient's Line Management, coordinate and conduct an annual compliance review of the Services Recipient's legal and other requirements that pertain to health and safety. Where required, the Services Provider shall develop appropriate protocols for the evaluation of health and safety compliance, in accordance with the Services Recipient's EHSMS procedures. The Services Provider shall also prepare and provide to the Services Recipient a written report summarizing the findings of the compliance review within 3 weeks of the field visits.

**5. Miscellaneous Services**

The Services Provider shall:

- attend Safety Meeting presentations given by both parties and provide support on urgent items or significant rule and regulation changes
- provide Job Planning Assistance including site visits, upon request
- review quality of work process inspections performed by the Services Recipient and recommend improvements, upon request
- perform work process inspections upon request and provide results to the Services Recipient
- provide the Services Recipient with a monthly written report at the end of each month during the term of the Agreement wherein it will describe the costs and accomplishments of these miscellaneous services provided by its personnel for the said month.

**B. Price and Terms of Payment**:

The Services Recipient shall pay to the Services Provider for the safety services, based on actual time and expenses incurred, in accordance with the hourly rates referred to in the Agreement.

In addition, the Services Recipient will pay the cost of the administration and reporting in respect of the safety services, material, travel and per diem costs related to the provision of the safety services. The Services Recipient will arrange and pay for the scheduling of charter flights to the Services Recipient's sites.

**C. Service Levels:**

None.

## FLEET SERVICES:

### A. Description of Services:

The Services Provider shall provide the Services Recipient with the following fleet management, maintenance, repair and rental services relating to the use of transport and work equipment:

a) Inspections, maintenance and repair of fleet transport and work equipment. The identification and completion of minor repairs and maintenance will be the Services Recipient's responsibility and at the Services Recipient's expense.

b) Supply of fleet licensing and provision of insurance as per Hydro One Inc. requirements.

c) Advise on fleet planning and acquisition as per the Services Recipient's evolving requirements. Increase or decrease of fleet compliment will be reviewed annually and fees paid adjusted accordingly.

d) Supply the current transport and work equipment complement for the fee specified,

e) Co-ordinate the replacement program including assistance with justifications for additions and replacements to current complement.

### B. Price and Terms of Payment:

The Services Recipient shall pay to the Services Provider the depreciation costs of the Services Recipient's vehicles and the Services Recipient's costs for fuel, labour and external repairs. The scheduling of charter flights to the Services Recipient's sites will be arranged and paid for directly by the Services Recipient.

### C. Service Levels:

The Services Provider shall, on a monthly basis during the term of the Agreement, provide the Services Recipient with a written summary of the total fleet costs by transport and work equipment unit and a written monthly fuel usage report for any equipment, spare parts, material and fuel purchases made by the Services Recipient from the Services Provider using the fleet credit card.

## ENVIRONMENTAL SERVICES:

### A. Description of Services:

The Services Provider shall provide the Services Recipient with the following environmental services as required:

- Quarterly Legislative Review
- Compliance Reviews and compliance support
- Emission Calculations and verification
- Certificate of Approval Amendments
- Support for remediation projects
- Investigations of diesel fuel alternatives
- Waste Management support
- Emergency response support

### B. Price and Terms of Payment:

The Services Recipient shall pay to the Services Provider the cost of time and materials required to perform these services.

### C. Service Levels:

All environmental services will be provided by the Services Provider in accordance with a jointly agreed work plan. Quarterly reviews of progress to be performed.

## ENGINEERING SERVICES:

### A. Description of Services:

The Services Provider shall provide the Services Recipient with the following engineering services:

**Drawing Services**

- Modify contractor drawings for designated stations as required and incorporate them into Meridian
- Make up connection and elementary wiring diagrams, mechanical layout and architectural drawings as required
- Develop connection wiring and elementary wiring diagrams for switchgear design that resembles the standards used by the Services Provider

**Technical Support**

- Assist in the development of Distributed Generation Connection Requirements
- Provide technical analysis of station transformer equipment and arcflash requirements for switchgear
- Assist with fuse co-ordination analysis

### B. Price and Terms of Payment:

The Services Recipient shall pay to Services Provider for these engineering services on a time and materials basis.

### C. Service Levels:

None.

**FLIGHT SAFETY SERVICES:**

**A. Description of Services:**

The Services Provider shall provide the Services Recipient with the following services related to flight safety:

1. Monitor all aviation occurrences between the Services Recipient and the commercial passenger charter companies with which it contracts, which occurrences shall include but not be limited to the following:

   - Accidents, incidents or occurrences as defined in GEN 3.3 of the Aeronautical Information Publication and the Canadian Aviation Regulations

   - Non-airworthiness defects (*cosmetic repairs*) and airworthiness defects (*that would result in the aircraft being grounded until repaired*)

   - Feedback from the Flight Evaluation Report *(internal report used to provide feedback from passengers and pilots to the Services Recipient to identify aircraft and contract problems*)

   - All incidents deemed to be High MRPH (*High Maximum Reasonable Potential for Harm*)

   - occurrences of a lesser risk, low MRPH, and occurrences handled at the Services Recipient's local operations level in Thunder Bay; the Services Provider shall track these occurrences and the Services Recipient when the number of these occurrences becomes of concern.

2. Assess, control and respond to occurrence reports.

3. Provide Team Lead/key resource for all High MRPH incident investigations.

4. Provide charter contract administration of all technical job specifications along with liaison representation with the Services Recipient's Superintendent of Operations and maintenance for new pilot interviews as well as current pilot presentations.

5. Assist with the planning of and participate in the annual Flight Safety Staff Meeting which shall be arranged by the Services Recipient at a date and time to be mutually agreed upon by the Services Recipient and the Services Provider. The Services Provider will arrange for its "Flight Safety Officer" to attend and present new and current information relevant to flight charter contracts and the aviation industry including a presentation of related flight safety information, approved pilot and aircraft lists, audit and monitoring results, and corrective action feedback.

6. Perform pre-award audits and provide a summary report on any fixed wing charter carriers prior to the award of any contract for passenger charter air service.

### B. Price and Terms of Payment:

The Services Recipient shall pay to Services Provider for these flight safety services on a time and materials basis.

In addition, the Services Recipient will pay the cost of the administration and reporting in respect of this Contract, material, travel and per diem costs related to the provision of the Services described in this Contract. The scheduling of charter flights to the Services Recipient's sites will be arranged and paid for by the Services Recipient.

### C. Service Levels:

The Services Provider will report on a monthly basis the cost and accomplishment of the Services provided by its personnel.

**DISTRIBUTION PLANNING TECHNICAL SERVICES:**

**A. Description of Services:**

The Services Provider shall provide the Services Recipient with the following services related to distribution planning:

- conduct fuse co-ordination studies;
- carry out distribution system modeling;
- conduct short circuit/fault analyses;
- conduct tingle voltage studies;
- produce engineering drawings for unique situations/requirements;
- conduct voltage irregularity analyses;
- distribution Lines and Metering construction standards support;
- special distribution engineering standard support;
- GIS data maintenance and migration support;
- distribution design technology and tool support;
- distribution metering technical support;
- distribution lines technical support; and
- support with ESA Regulation 22/04.

**B. Price and Terms of Payment:**

The Services Recipient shall pay to Services Provider for the distribution planning technical services on a time and materials basis.

**C. Service Levels:**

None.

## JOINT USE SERVICES:

### A. Description of Services:

The Services Provider shall provide the Services Recipient with the following services in order to assist the Services Recipient with its Joint Use Program:

(a) Support and participate with the Services Recipient's staff in drafting, negotiating, tracking and arranging for execution of joint use agreements for the Services Recipient as required and requested by the Services Recipient;
(b) add, remove and change permits or similar authorizations and update and/or remove documents as required by the Services Recipient;
(c) issue invoices to tenants/licensee for the Services Recipient in accordance with the Services Recipient's joint use agreements and manage the related accounts receivables accordingly;
(d) manage and input information concerning the Services Recipient's joint use agreements into the Services Provider's "Joint Use" database and maintain said information separate from the Services Provider's own joint use information;
(e) liaise with the Services Provider's "Joint Use" database on behalf of the Services Recipient; and
(f) provide training to the Services Recipient's staff with regard to the Database, joint use agreements and other joint use activities, all as requested by the Services Recipient.

### B. Price and Terms of Payment:

The annual price for the performance of the Services for the Services Recipient shall be $15,000.00, exclusive of any sales and use taxes, as may be applicable.

### C. Service Levels:

None.

## HEALTH AND SAFETY SERVICES:

**A. Description of Services:**

The Services Provider shall provide the Services Recipient with the following services in order to assist the Services Recipient with its health and safety program:

**(i) WSIB Claims Management**

- support the supervisor in WSIB reporting and early and safe return to work;
- provide guidance and interpretation of WSIB policy and legislation to the Services Recipient's line management;
- manage the financial impact of the WSIB claim cost statement and submit monthly premium remittance the Workplace Safety and Insurance Board on behalf of the Services Recipient.

**(ii) Care Management**

- support the Services Recipient's sick leave program that deals with sick leaves greater than 5 days and that is medically supported;
- support (via the Services Provider's Disability Management Consultant, the affected supervisor and employee through a third party provider while the employee is absent from work due to a major medical absence with a view to assisting in providing the right care at the right time for the right outcome

**(iii) Long Term Disability (LTD)**

- provide the Services Recipient with LTD case management services including application assignment to LTD payroll and ongoing case management and rehabilitation activities through a third party provider

**(iv) Audiometric Testing**

- support the Services Recipient's supervisors to carry out an Audiometric Program through the Health, Safety and Environment Management System (HSEMS) that establishes the requirement to implement operational controls to minimize a health and safety risk

**(v) Respiratory Screening Program**

- support the Services Recipient's supervisors in determining how respirators will be managed at the Services Provider's premises

**(vi) Ergonomic Assessments**

- support the workplace parties through the Workstation or Vehicle Ergonomic Assessment process.

**(vii) Physical Demands Analysis (PDAs)**

- develop and maintain Physical Demand Analyses to assist with the Services Recipient's employees fitness to return to work

**B. Price and Terms of Payment:**

The Services Recipient shall pay to Services Provider for these health and safety services on a time and materials basis.

**C. Service Levels:**

None.

Schedule "D"

**COMMERCIAL GENERAL LIABILITY INSURANCE CERTIFICATE**
**SUPPLY ONLY TRADES**

| |
|---|
| **Issued in favour:** |
| |
| |
| |
| |
| **Insured:** |
| XXXXXXXXXXXXXXXXXXXXX |
| XXXXXXXXXXXXXXXXXXXXX |
| XXXXXXXXXXXXXXXXXXXXX |
| XXXXXXXXXXXXXXXXXXXXX |
| |

This is to certify that policies of insurance listed below have been issued to the insured named above for the period indicated and cover operations of the insured in connection with the **SERVICES BEING PERFORMED UNDER THE MASTER AGREEMENT**

| | | Effective | Expiration | |
|---|---|---|---|---|
| | Policy | Date | Date | |
| **Type of insurance** | **Number** | **MM/DD/YR** | **MM/DD/YR** | |
| | | | | |
| **Commercial General Liability** | | | | $5,000,000 |
| (X) Blanket Contractual Liability | | | | $5,000,000 |
| (X) Broad Form Property Damage | | | | $5,000,000 |
| (X) 3rd Party Property damage including loss of use | | | | |
| (X) Sudden and Accidental Pollution Liability coverage | | | | |
| (X) Products and Completed operations | | | | |
| (X) Employer's Liability | | | | |
| (X) Non-Owned Automobile Liability | | | | |
| | | | | |
| **Automobile Liability** | | | | |
| (X) Owners | | | | $5,000,000 |
| | | | | |

**Special Condition**

Commercial General Liability policy shall i) include Hydro One Remote Communities Inc. as a named insured subject to sole agent provisions and ii) be primary non-contributing with and not excess of any other insurance available to Hydro One Remote Communities Inc. iii) contain a cross liability and severability of interest clause

The Insurer agrees to notify the certificate holder by registered mail not less than 30 days prior to any material change, which reduces or restricts cover, cancellation, termination or non-renewal.

| | |
|---|---|
| Date: | |
| Name of Insurer: | |
| By: Authorized Official of the Insurance Company | |
| Print Name and Title of Above Official | |

## Schedule "E"

## ADDITIONAL INSURANCE COVERAGES

1.01 Commercial General Liability and Excess Liability Insurance on an occurrence basis in an amount not less than $5,000,000 inclusive for both bodily injury, including death, personal injury and damage to property, including loss of use thereof, for each occurrence. To achieve the desired limit, umbrella or excess liability insurance may be used.

Coverage shall specifically include, but not be limited to, the following

- i) Blasting, pile driving, caisson work, underground work;
- ii) Products & Completed Operations including a provision that such coverage to be maintained for a period not less than 24 months post Final Performance;
- iii) Errors and omissions integral to the operation of the Insured;
- iv) Tenant's Legal Liability;
- iv) Pesticide Liability; and
- v) Rail Liability.

1.02 Contractor's Equipment Insurance covering equipment and tools, owned, rented or leased for the full replacement cost of such equipment on an "All Risks" basis including marine based risk subject to normal exclusions.

1.03 Pollution Liability Insurance: When remediation or abatement is included in the work, the Services Provider shall purchase a policy with limits of not less than $5,000,000 per occurrence covering bodily injury and property damage claims, including cleanup costs as a result of pollution conditions arising from the Services Provider's and/or its subcontractors' operations and completed operations. Completed operations coverage will remain in effect for no less than 3 years after final completion. The policy will have a retroactive date before the start of the work. To achieve the desired limit, umbrella or excess liability insurance may be used.

1.04 Errors & Omissions Insurance: Engineering, Architectural, Design or other Professionals or Consultants and the EPCM (Engineering, Procurement, Construction and Maintenance). The Services Provider shall, at all times, maintain in full force and effect professional liability insurance in an amount not less than $10,000,000 aggregate limit covering the period from start of conceptual design through to completion of the project and for a further discovery period of 5 years from the issuance of the certificate of Final Completion.

1.05 Transit insurance (including loading, unloading and storage during the course of transit including storage at secondary processing facilities) against All Risks of physical damage to the property of the Services Recipient in the Services Provider's care, custody and control until such property is received on the Services Recipient's site.

1.06 Aircraft and watercraft liability insurance with respect to owned or non-owned aircraft and watercraft if used directly or indirectly in the performance of the Services, including use of additional premises, shall be subject to limits of not less than $5,000,000.00 inclusive per occurrence for bodily injury, death and damage to property including loss of use thereof and limits of not less than $5,000,000.00 for aircraft passenger hazard. Such insurance shall be in a form acceptable to the Services Recipient. The policies shall be endorsed to provide the Services Recipient with not less than 15 days' notice in writing in advance of cancellation, change, or amendment restricting coverage. To achieve the desired limit, umbrella or excess liability insurance may be used.

1.07 Such other insurance as is mutually agreed upon between the Services Recipient and the Services Provider.

Where any of the above coverages are required for any of the Services, the Services Provider shall be bound by and comply with the following:

1. Prior to the commencement of the performance of the Services, the Services Provider shall provide the Services Recipient with a certificate of insurance completed by a duly authorized representative of its insurer certifying that at least the minimum coverages required here are in effect and that the coverages will not be cancelled, nonrenewed, or materially changed by endorsement or otherwise so as to restrict or reduce coverage, without 30 days' advance written notice by registered mail, or courier, receipt required, to:

    Manager, Risk & Insurance Department, Hydro One Remote Communities Inc. 483 Bay Street, TCT7, South Tower, Toronto, Ontario. M5G 2P5

    If any of the coverages are required to remain in force after final payment, an additional certificate evidencing continuation of such coverage will be submitted with the Services Provider's final invoice.

2. All deductibles shall be to the account of the Services Provider.

3. All insurance noted above shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by the Services Recipient.

4 A waiver of subrogation shall be provided by the insurers to the Services Recipient for coverages 1.02 (Contractor's Equipment).

6. The Services Recipient shall be included as a Named Insured under coverages noted in 1.03 (Pollution Liability) subject to Sole Agent provisions.

7. Coverages noted in 1.03 (Pollution Liability) shall contain a Cross Liability clause and a Severability of Interests clause.

8. Coverage provided for shall not be invalidated by actions or inactions of others.

## **Schedule "F"**

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

*The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.*

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

**THIS AGREEMENT** made in duplicate this 1st day of January, 2017 (the "Effective Date").

**BETWEEN:**

**HYDRO ONE NETWORKS INC.**
**(the "Services Provider")**

**- and -**

**HYDRO ONE REMOTE COMMUNITIES INC.**
**(the "Services Recipient")**

## 1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to the Services Recipient by the Services Provider in accordance with the terms and conditions herein. Except as otherwise specified, the term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

## 2.0 SERVICES

The Services Provider shall provide supply chain services to the Services Recipient, which collectively constitute the Services and which are more particularly described in Schedule "A" attached hereto, as may be required by the Services Recipient from time to time during the term of this Agreement.

## 3.0 FEES PAYABLE

(a) The annual price for the performance of the Services for the Services Recipient shall be $76,000, exclusive of any sales and use taxes, as may be applicable. The said annual price for the Services shall be paid by the Services Recipient to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party. In addition, the Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, the Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

c) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for purposes of HST. For the purposes of this Agreement, "HST" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

## 4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:

(i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;

(ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and

(iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) The Services Recipient represents and warrants that:

(i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and

(ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

## 5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law**: The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's document entitled "Security Policy" (SP 1686 R1) dated December 2016 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at any of the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: The parties shall, after the Effective Date, meet at least twice a year during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

## 6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "**Dispute**") shall be settled in accordance with this Section. The aggrieved party shall send the other party written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. A director-level employee of each party (as chosen by each party respectively) shall confer in an effort to resolve the Dispute. If the director-level employees are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the parties shall submit the Dispute to the President of Hydro One Limited for resolution.

## 7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

### (a) Confidentiality:

Each party (the "**Receiving Party**") shall maintain in strict confidence all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from the other party (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "**Disclosing Party Representatives**") (collectively the "**Confidential Information**"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "**Receiving Party Representatives**") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as this term is defined in the *Personal Information Protection and Electronic Documents Act* (Canada), as it may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party, including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

**(b) Intellectual Property:**

The Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

**(c) Survival of Obligations:**

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

## 8.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Agreement and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, neither party shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other or by any third party claiming through or under the other.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

## 9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

**HYDRO ONE REMOTE COMMUNITIES INC.**
483 Bay Street,
South Tower, 8th Floor
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT 12
Telephone: 416-345-6698
Telecopier: 416-345-6356

**HYDRO ONE NETWORKS INC.**
483 Bay St.
South Tower, 6th Floor Toronto, Ontario M5G 2P5
Attention: **Rob Berardi**
Telephone: (416) 345-4277
Telecopier: (416) 345-6833

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

## 10.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by either party without the prior written consent of the other party, which consent shall not be unreasonably withheld; provided, however, that a party may assign this Agreement or any rights, remedies or liabilities to any of its affiliates (as this term is defined in the Ontario *Business Corporations Act*, as amended) without the need for prior consent, in which case the assignor shall provide the other party with written notice of the assignment within 10 days after the effective date thereof. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

**11.0 RELATIONSHIP OF PARTIES:**

Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not present themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either party which could establish any apparent relationship of agency, employment, joint venture or partnership and neither party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other party to any other person nor with respect to any other action of the other party.

**12.0 SCHEDULES**

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

**13.0 COUNTERPARTS**

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

**IN WITNESS THEREOF** the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

**HYDRO ONE NETWORKS INC.**

Robert Berardi

Name: Rob Berardi
Title: Director, Supply Chain
I have authority to bind the corporation

**HYDRO ONE REMOTE COMMUNITIES INC.**

Name: Kraemer Coulter
Title: Managing Director
I have authority to bind the corporation.

## Schedule “A”

**DESCRIPTION OF SERVICES:**

The Services Provider shall provide the Services Recipient with the following supply chain services:

- management and procurement;
- vendor management;
- process development;
- data management;
- investment recovery.

**<u>Schedule "B"</u>**

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

**THIS AGREEMENT** made in duplicate this 1st day of January, 2017 (the "Effective Date").

**BETWEEN:**

**HYDRO ONE REMOTE COMMUNITIES INC.**
**(the "Services Provider")**

**- and -**

**HYDRO ONE NETWORKS INC.**
**(the "Services Recipient")**

## 1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to the Services Recipient by the Services Provider in accordance with the terms and conditions herein. Except as otherwise specified, the term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

## 2.0 SERVICES

Subject to the Services Provider's availability of personnel and resources, which availability shall be determined by the Services Provider in its sole discretion, the Services Provider shall provide metering work, lines work and training for lines work to the Services Recipient, which collectively constitute the Services and which are more particularly described in Schedule "A" attached hereto, as may be required by the Services Recipient from time to time during the term of this Agreement.

## 3.0 FEES PAYABLE

(a) The price for the performance of the Services shall be on a time and materials basis in accordance with the Services Provider's 2017-2018 hourly rates by job category, which rates may be amended from time to time by mutual agreement of the parties. The parties acknowledge and agree that the Services Recipient has received the Services Provider's 2017-2018 hourly rates from the Services Provider.

(b) The parties agree that the price for the Services shall be paid by the Services Recipient to the Services Provider by direct time reporting through Hydro One Inc.'s payroll system.

(c) In addition, the Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(d) If at any time during the performance of the Services, the Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

(e) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for purposes of HST. For the purposes of this Agreement, "HST" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

## 4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:
  (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
  (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
  (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) The Services Recipient represents and warrants that:
  (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
  (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

## 5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law**: The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's document entitled " Security Policy" (SP 1686 R1) dated December 2016 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **<u>Safety and Security Measures</u>**: When any part of the Services is to be performed at any of the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **<u>Meetings</u>**: The parties shall, after the Effective Date, meet at least once during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

## 6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other party written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. A director-level employee of each party (as chosen by each party respectively) shall confer in an effort to resolve the Dispute. If the director-level employees are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the parties shall submit the Dispute to the President of Hydro One Limited for resolution.

## 7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

### (a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from the other party (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as this term is defined in the *Personal Information Protection and Electronic Documents Act* (Canada), as it may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party, including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

**(b) Intellectual Property:**

The Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

**(c) Survival of Obligations:**

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

## 8.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Agreement and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, neither party shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other or by any third party claiming through or under the other.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

## 9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

**HYDRO ONE REMOTE COMMUNITIES INC.**
483 Bay Street,
South Tower, 8th Floor
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT 12
Telephone: 416-345-6698
Telecopier: 416-345-6356

**HYDRO ONE NETWORKS INC.**
483 Bay St.
South Tower, 7th Floor
Toronto, Ontario M5G 2P5
Attention: **Ryan Lee**
Telephone: (416) 345-5158
Telecopier: (416) 345-5063

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

## 10.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by either party without the prior written consent of the other party, which consent shall not be unreasonably withheld; provided, however, that a party may assign this Agreement or any rights, remedies or liabilities to any of its affiliates (as this term is defined in the Ontario *Business Corporations Act*, as amended) without the need for prior consent, in which case the assignor shall provide the other party with written notice of the assignment within 10 days after the effective date thereof. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

## 11.0 RELATIONSHIP OF PARTIES:

Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not present themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either party which could establish any apparent relationship of agency, employment, joint venture or partnership and neither party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other party to any other person nor with respect to any other action of the other party.

## 12.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

## 13.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

**IN WITNESS THEREOF** the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

| | |
|---|---|
| **HYDRO ONE NETWORKS INC.** | **HYDRO ONE REMOTE COMMUNITIES INC.** |
| Name: Ryan Lee | Name: Kraemer Coulter |
| Title: Director, Management Accounting and Reporting | Title: Director |
| I have authority to bind the corporation | have authority to bind the corporation. |

## 10.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by either party without the prior written consent of the other party, which consent shall not be unreasonably withheld; provided, however, that a party may assign this Agreement or any rights, remedies or liabilities to any of its affiliates (as this term is defined in the Ontario *Business Corporations Act*, as amended) without the need for prior consent, in which case the assignor shall provide the other party with written notice of the assignment within 10 days after the effective date thereof. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

## 11.0 RELATIONSHIP OF PARTIES:

Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not present themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either party which could establish any apparent relationship of agency, employment, joint venture or partnership and neither party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other party to any other person nor with respect to any other action of the other party.

## 12.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

## 13.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

**IN WITNESS THEREOF** the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

**HYDRO ONE NETWORKS INC.**

Name: Ryan Lee
Title: Director, Management Accounting and Reporting
I have authority to bind the corporation

**HYDRO ONE REMOTE COMMUNITIES INC.**

Name: Kraemer Coulter
Title: Director

have authority to bind the corporation.

## Schedule "A"

**DESCRIPTION OF SERVICES:**

Subject to the Services Provider's availability of personnel and resources, which availability shall be determined by the Services Provider in its sole discretion, the Services Provider shall provide the Services Recipient with the following services as may be required by the Services Recipient from time to time during the term of this Agreement:

a. Metering/Technician Work:

- update, install, reverify and sample meters
- Smart meter change-outs
- line layout, estimating and staking
- voltage/current surveys and responding to voltage/current complaints
- update Emergency Site Plans

b. Lines Work:

- maintain the Services Recipient's transmission and distribution system in Northwestern Ontario by providing the following activities, as may be requested by the Services Recipient:
- power line maintenance, construction and repair
- trouble Call Response, power restoration and storm damage repairs

c. Training:

- Provide lines apprenticeship program instruction services

## Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

*The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.*

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

# PURCHASE OF NON-AFFILIATE GOODS AND SERVICES

## 1.0 INTRODUCTION

This Exhibit describes how Remotes purchases goods and services from third parties other than its affiliates.

## 2.0 THE PROCUREMENT OF GOODS AND SERVICES FROM NON-AFFILIATES

In compliance with the Supply Chain Policy set out as Attachment 1 to this Exhibit, Remotes acquires materials and services from non-affiliates by using one or more of the following processes: request for information, request for proposals, request for quotes, request for pre-qualification, contract harmonization, direct negotiation (single sourcing) and sole sourcing process.

Remotes works with buyers in Hydro One Networks' procurement group when making purchases. Large purchases such as contracts for fuel and flights are conducted through extensive RFP processes, where potential suppliers are ranked based on pricing, proof of ability (resources, service, experience and quality), safety performance and Indigenous involvement in the business. Remotes leverages the bulk buying power of Hydro One and the existing Supply Chain infrastructure to secure routine purchases of materials, such as line supplies.

For services within communities Remotes routinely supports local Indigenous business and local employment opportunities for services such as meter reading, operator services, fuel handling, forestry services and equipment rentals. Remotes enters into mutually beneficial fuel purchase agreement with local First Nation businesses that are able to secure and store winter road fuel.

All purchases of goods and services go through a rigorous quality control process and are reviewed by Law and Supply Chain to ensure value for money and adherence to Hydro One policies.

Purchases are authorized by the appropriate position identified in Hydro One’s Expenditure Authority Register (“EAR”). The EAR defines approval authorities assigned to employees within Hydro One and it is a key element of the internal control framework. Employees, as stewards of the Company’s assets, are expected to exercise prudent business judgment when delegating and exercising the authority limits in the EAR.

# Supply Chain Policy

## Purpose and Scope

The primary purpose of the Supply Chain Policy is to communicate and reinforce desired values and expectations of the supply chain activities of Hydro One Limited, its subsidiaries and the affiliates it controls (referred to in this document as 'Hydro One' or the 'Corporation').

This policy applies to Hydro One and its outsourcing partner.

## Revision Statement

Guiding principles have been updated to reflect a more commercial mindset regarding linkage of procurement to outcomes. Reference to the Requisitioner's and the Purchasing Procedures have been replaced with the Requisitioner's and Buyer's Guide respectively. References to the Consultants and Professional Services Policy (SP0707) have been removed.

## Principles

Supply Chain will:

- Acquire materials and services through a process that drives value for money, transparency to its internal customers, and builds mutually valuable relationships with key suppliers.
- Ensure the right materials and services are delivered to the right place at the right time in a cost effective manner.
- Source materials and services with consideration to health, safety and the environment and corporate social responsibility.
- Promote business and workforce development for Aboriginal Businesses.
- Achieve operational excellence through continuous improvement in collaboration with Supply Chain's Customers and Suppliers.
- Manage its outsourcing partner to align with these principles.

## 1.0 Requirements

The key requirements of each Supply Chain function are as follows:

Strategy and Oversight:

- Provide a strategic, cost effective, data driven and analytical planning approach to Supply Chain processes.
- Direct continuous improvement initiatives to achieve operational excellence and cost effectiveness.
- Ensure an effective governance process is in place to manage change.

Sourcing:

- Develop and execute a strategic procurement plan to identify materials and services needed to meet business requirements at the best value for money.
- Employ a mix of procurement processes, including sole source, direct negotiation, and bidding processes that provide the best business outcome.

- Identify and attract qualified suppliers that provide quality products and services.
- Provide opportunity for increased Aboriginal Business participation in the provision of products and services.

Purchasing:

- Process Purchase Requisitions on a timely basis to ensure that customer's needs are met.
- Promote improved requisitioning through effectively documented processes and education.

Inventory Management:

- Align to the Inventory Policy (SP0732).
- Manage inventory at optimal levels and locations to satisfy operations.
- Monitor and control the accuracy of inventory data.
- Re-deploy, return or dispose of material to maximize cost savings considering environmental impact.

Logistics:

- Determine the most efficient and economical method to store and distribute materials from Suppliers to Customers.
- Facilitate the movement of returnable containers to Suppliers.

Accounts Payable:

- Remit authorized and timely payments to suppliers in accordance with the terms and conditions of the respective contracts.
- Capture payments accurately and completely in Hydro One systems, and ensure accurate account distributions.

Customer Service:

- Provide centralized support to customers and suppliers so interactions with Supply Chain are seamless. Data Management
- Utilize business applications, information management methods, and data management tools to implement procedures and an infrastructure to support the integration and shared use of accurate, timely, consistent and complete Supply Chain Master Data.

# 2.0 Definitions

None

# 3.0 References

Expenditure Authority Register
SP0829 - Code of Business Conduct
SP0849 - Corporate Disclosure Policy
SP0732 – Inventory Policy
SP0733 - Inventory Procedure
SP1374 - Aboriginal Procurement Procedure
SP0327 - Health, Safety and Environmental Policies
SP0826 - Sourcing Procedure
SP1254 - Buyer's Guide (formerly Purchasing Procedure)
SP1233 - Requisitioner's Guide (formerly Requisitioner's Procedure)

# 4.0 Document Management

| | |
|---|---|
| **Owner/Functional Responsibility** | Director, Supply Chain |
| **Approver** | Vice President, Shared Services |
| **Approval Date** | July 28, 2016 |
| **Effective Date** | July 29, 2016 |
| **Last Reviewed Date** | July 22, 2016 |
| **Next Review Date** | July 22, 2018 |

# 5.0 Appendices

None

# CORPORATE ORGANIZATION CHARTS

## 1.0 INTRODUCTION

This schedule describes the current organization of Remotes' business, beginning with an overview of the parent company (Hydro One Ltd Inc.) and a brief summary of Hydro One Ltd.'s principle subsidiary businesses.

## 2.0 COMMON CORPORATE COSTS

Hydro One Inc. was incorporated under Ontario's Business Corporations Act and was incorporated on December 1, 1998 and was wholly owned by the Province of Ontario. On October 31, 2015, Hydro One Limited, a wholly owned subsidiary of the Province, acquired all issued and outstanding shares of Hydro One from the Province. The principle businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Figure 1 below shows Hydro One Ltd.'s principal subsidiaries. Information on financial transactions between Remotes and its Hydro One Ltd affiliates can be found in Exhibit A, Tab 6, Schedule 1, Attachments 1 to 5 inclusive.

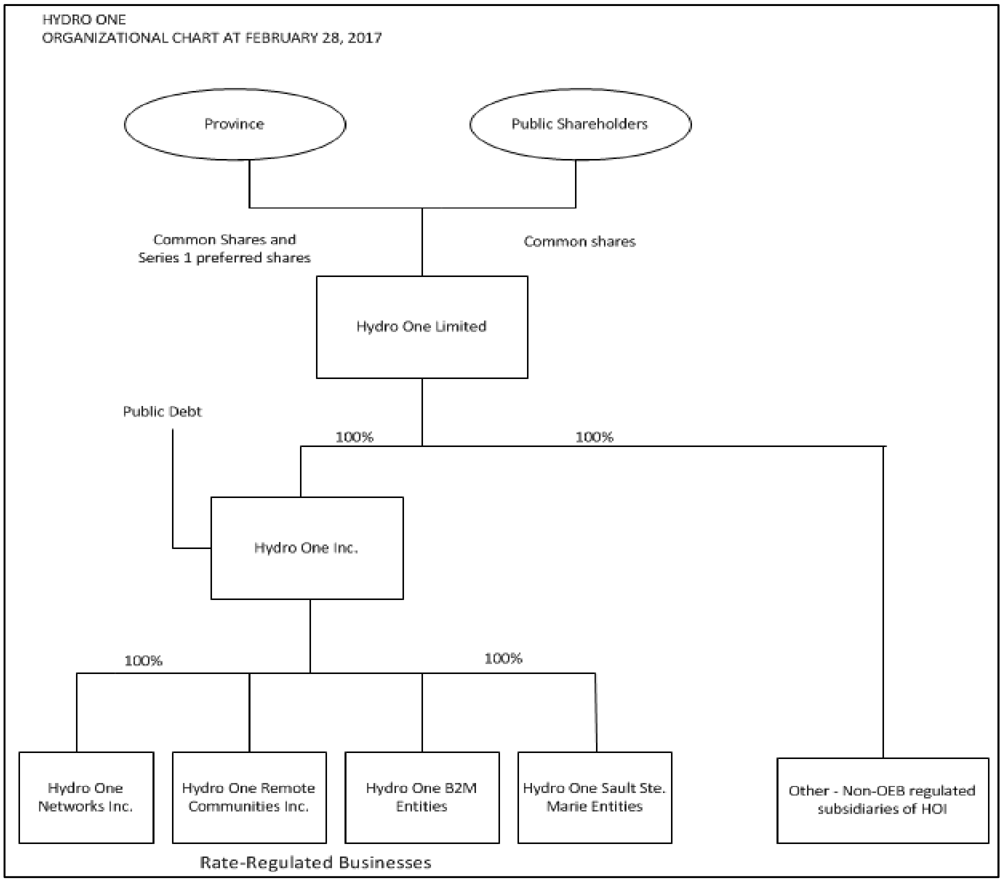


**Figure 1**

**Hydro One Ltd.**

## 3.0 HYDRO ONE REMOTE COMMUNITIES ORGANIZATIONAL CHART

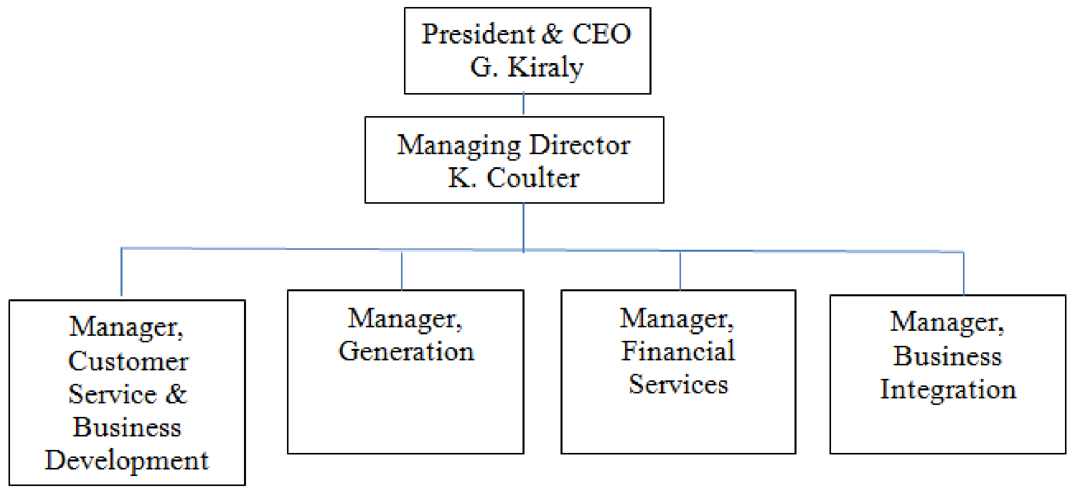


**Figure 2**

**Hydro One Remote Communities Inc. Organizational Chart**

# GOVERNANCE AND CONTROL FRAMEWORK

## 1.0 CORPORATE ORGANIZATION

The Corporate Governance structure and Internal Control Framework of Hydro One Inc. provide reasonable assurance regarding Remotes' effective and efficient operations, reliable financial reporting, and compliance with applicable laws and regulations. Hydro One Inc. is the parent and sole shareholder of Remotes, and Hydro One Limited is the parent and sole shareholder of Hydro One Inc.

Figure 1 in Exhibit A, Tab 7, Schedule 1 shows the organizational structure of Hydro One Limited as of February 28, 2017. This chart is simplified and does not include all legal entities within Hydro One Limited's organizational structure.

Corporate governance is the mechanism by which a corporation ensures independent oversight of management activities on behalf of the shareholder(s). For Hydro One Inc., the Board of Directors and its associated committees fulfill this objective and provide direction and accountability to senior officers to prudently and ethically manage the company's business and affairs, as well as the review and/or approval of mission, goals and business objectives, organizational authorities and business plans.

Hydro One Inc.'s internal organization is led by its President and Chief Executive Officer whose direct reports include: the Chief Financial Officer; the Chief Operating Officer; the Executive Vice-President and Chief Legal Officer; the Executive Vice-President of Customer and Corporate Affairs; the Executive Vice-President and Chief Human Resources Officer; Executive Vice-President of Strategy and Corporate Development; and the Vice-President of the Office of the President & CEO.

Remotes has two officers and three directors. The Chair of Remotes' Board of Directors is the Chief Operating Officer of Hydro One Inc. The accountabilities and responsibilities of Remotes' officers and directors include the approval and adoption of a business plan that is included in Hydro One Inc.'s consolidated plan, oversight of risk management, and review of Remotes' overall business performance.

## 2.0 INTERNAL CONTROL FRAMEWORK

Internal controls ensure that Hydro One Inc. achieves its mission and goals, by enabling management to deal with rapidly changing economic and competitive environments, customer demands and priorities, and restructuring for future growth. Internal controls promote efficiency, reduce risk of asset loss, and help ensure the integrity and reliability of financial statements and compliance with laws and regulations. These controls of Hydro One Inc. extend to the operations of Remotes, as a wholly-owned subsidiary of Hydro One Inc.

Hydro One Inc.'s Internal Control Framework has five components: (1) Control Environment, (2) Risk Assessment, (3) Control Activities, (4) Information and Communication, and (5) Monitoring. The framework further addresses the appropriate elements of each component at the entity (Board) level, corporate (senior management) level and operational (local) level. The framework is consistent with accepted external standards and control criteria set out by such standard setting bodies as the Chartered Professional Accountants and the U.S. Committee of Sponsoring Organizations of the Treadway Commission. Key components of the framework are described in more detail below.

The "Control Environment" refers to direction and oversight from the top of the organization. The control environment component in the framework captures the notion of ethical and prudent financial management as established by the Board of Directors and senior management, and sets the tone for all financial and project management policies and practices established at lower levels. Regular education sessions on policies, processes and practices/procedures are also provided to all staff.

Hydro One Inc. has a formal Code of Business Conduct and a Whistle Blower Policy which have been issued to and must be complied with by all staff. The Code of Business Conduct requires all management employees to sign an annual compliance form to document that they have read, understood and complied with the Code, and that all conflicts or potential conflicts of interest have been disclosed. The Corporate Ethics Officer ensures that this process is performed on a timely basis and that a compliance register is maintained and submitted to the President and CEO of Hydro One Inc. Lastly, individual performance contracts of management employees are intended to capture the understanding between a manager and a direct report as to the results expected and the means by which such performance results will be achieved.

"Risk Assessment" involves the identification and analysis by management of the key risks to achieving the company's business objectives. Such an assessment is performed, at least, annually, and provides the basis for business planning decisions. Programs that mitigate existing risks to acceptable residual levels, or provide mitigation for emerging risks, are captured in business plans. Projects and programs underway are regularly assessed for new and changing risks. Moreover, at the operational level, extensive emergency and contingency plans exist and are regularly tested and updated.

"Control Activities" refers to the systems, policies and procedures that ensure that management’s objectives are achieved and risk mitigation plans are carried out. Policies and procedures exist to govern annual, monthly and day to day operations at the business unit and local levels. Each revised policy has an issue date and last review date and are available on an internal web site.

One of the foundations of good control is the establishment of appropriate levels of authority for spending and other business decisions. The delegation and exercise of authorities are governed by 'Guiding Principles', the Code of Business Conduct, and policies and procedures. The approval of the business plans and budgets establish authorized spending levels.

The budgeting and business planning process is also a critical element of effective internal controls. Annually a budget and business plan are prepared and submitted to the Board for approval. The budget and business plan set the parameters of the company's activities for a specific fiscal period. Remotes' corporate business plan may be found in Exhibit A, Tab 3, Schedule 2, Attachment 1.

The Executive Authorities Register (EAR) delegates authorities from the Board to senior management. Organizational Authority Registers (OARs) exist at subsidiary and business unit levels to delegate authorities from senior management to business unit and local levels.

"Information and Communication" supports all other control components. Pertinent information must be identified, captured and communicated in a form and timeframe that enables staff to carry out their responsibilities. Communication occurs to all staff from the Executive Vice President and Chief Financial Officer and from the Vice President, Corporate Controller with respect to new or changed policies and procedures. Communications on various internal control matters also occur regularly. And, as noted previously, policies and procedures can be found on internal websites at most locations or are available in other formats.

"Monitoring" covers the oversight of internal controls by management or independent parties outside the process; or the application of independent methodologies, such as customized procedures or standard checklists, by employees within a process. Monitoring also includes assessing the quality of internal controls over time and implementing required changes.

Management provides assurance with respect to internal controls and the validity of financial statements. This includes information on legal claims, changes in accounting policies, practices, systems, and procedures that have occurred in the period, and financial accounting matters that could have a significant impact on financial statements. Management also provides assurance that internal control systems, policies and procedures are in place and functioning properly and financial statements are a true representation of the business.

Every month, Remotes and every other line of business is required to conduct a detailed review of financial results by comparing operating results to budgets and responding to variances. Project details with major accounts are reconciled monthly to source sub-systems and suspense accounts are also explained and reconciled. Monthly control reports related to key aspects of operations financial and project activity are prepared centrally and delivered to managers for review and follow-up action as appropriate. A month-end close schedule is established to ensure timely production of financial statements. In addition, compliance testing of key financial activities is performed.

Compliance monitoring with respect to codes and policies is performed by multiple groups. Regulatory compliance is monitored by Regulatory Affairs. Internal Audit uses a risk-based audit approach for prioritizing audits and performs audits of areas of highest risk based on an annual program approved by the Hydro One Board’s Audit and Finance committee. Internal controls are reviewed on a recurring cycle, again linked to level of risk. Furthermore, regular review of all outstanding items from past audits is performed. Annual year-end audits are also conducted by Hydro One Inc.'s external auditor.

# PLANNING PROCESS AND ECONOMIC ASSUMPTIONS

## 1.0 INTRODUCTION

Business planning is performed annually and focuses on the development of a six year plan which comprises a detailed plan for the first three years in the planning cycle and a less detailed outlook for the remaining three-year period. The planning cycle in 2016 pertained to the 2017-2022 period. The results as they apply to 2018 (the test year) form the basis for the rate submission.

The typical annual business planning process consists of six stages:

1. Strategic direction and goals established;
2. Risk review and investment requirements;
3. Confirmation of strategic direction and goals with Hydro One Limited;
4. Development of economic outlook and forecast assumptions;
5. Development of plans and work programs; and
6. Approval by Hydro One Limited Senior Management and Board of Directors.

### 1.1 Strategic Direction and Goals Established by Senior Management

Remotes' strategic direction and goals are reviewed and established by its management team and are confirmed by Hydro One. The strategic goals are used by planners as the business plan is being developed. Remotes' corporate vision and strategic objectives are shown in Exhibit A, Tab 3, Schedule 2.

## 1.2 Risk Review and Investment Requirements

Annually, required investments are determined based on asset condition, engine hours, load growth and external factors (INAC funding, winter roads). Investments are then ranked against financial, operational, environmental, safety, regulatory and legal requirements and risks. The outcome of this process is a list of investments that is consistent with Remotes' strategic goals and takes into account levels of investment and associated risk mitigation against financial, operational, environmental, safety, regulatory and legal considerations. A final investment plan is then endorsed and confirmed by the Hydro One Inc. senior management team. The investment plan prepared during 2016 provides the basis for the 2018 plan.

## 1.3 Development of Economic Outlook and Planning Assumptions

To facilitate the preparation of the business plan, an economic outlook is developed and included with the planning instructions issued. This includes forecasts of key economic statistics, interest rates, labour escalation rates, income tax rates, and cost rates for benefits.

### 1.3.1 Consumer Price Index

Remotes uses the Consumer Price Index (CPI) as a planning tool to forecast expenditure level changes. The CPI provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in retail price of a representative shopping basket of about 600 goods and services from an average household's expenditures: food, housing transportation, furniture, clothing and recreation.

CPI-Ontario exhibits the inflationary environment in which Remotes operates. The CPI forecast is from IHS Global Insight June 2016 forecast.

For 2018, Hydro One assumed 2.0% annual inflation and cost escalators for construction and OM&A expense growth of 2.5% and 2.2%, respectively.

**Table 1**
**Ontario Consumer Price Index**

| % | Historical Years | | | | | Bridge Year | Test Years | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
| **CPI-Ontario*** | 1.4 | 1.1 | 2.3 | 1.2 | 2.1 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |

### 1.3.2 Cost of Capital

Remotes cost of capital is as described in Exhibit E1, Tab1, Schedule 1.

### 1.3.3 Interest Capitalized and Capitalization of Overheads

Remotes' interest capitalized rates and capitalization of overheads are as described in Exhibit C1, Tab 2, Schedule 1.

### 1.3.4 Labour Escalation

Specific details on annual labour escalation are provided below.

**a) Society Staff**

The Society of Energy Professionals Collective Agreement has reached an agreement to March 31, 2019. Economic increases are assumed to be 0.75% for the 2017-2022 business plan term and are slightly different from the Collective Agreement as it was not yet ratified when the business plan was finalized.

**b) PWU Staff**

The Power Workers' Union Collective Agreement has reached an agreement to March 31, 2018. Economic increases are assumed to be 1.0% for the 2017-2022 business plan term and are slightly different from the Collective Agreement as it was not yet ratified when the business plan was finalized.

**c) MCP Staff**

It is anticipated that a 2% annual increase per year in base pay for the 2017-2022 period.

**d) Incentive Plan Payouts**

All incentive plans have been discontinued, with exception of the MCP Short Term Incentive Plan. Payout under this plan is assumed to be 10% for the 2017-2022 business plan term.

#### 1.3.5 Income Tax Rates

Remotes' calculation of income taxes is as described in Exhibit D1, Tab 7, Schedule 1.

### 1.4 Development of Plans and Work Programs

During the planning process, plans and work programs are further refined consistent with the economic and forecast assumptions. As part of this process, sufficient detail is provided to facilitate preparation of the 2018 Rate Application. At the end of this process, senior management provides direction as necessary in order to balance the various factors under consideration including legal requirements, customer service levels, rate impacts and impacts on RRRP.

The operations, maintenance and administration ("OM&A") budget and the capital budget that result from this planning process are discussed at Exhibit D1, Tab 1, Schedule 1 and Exhibit B1, Tab 1, Schedule 1 respectively. Refer to Exhibit A, Tab 7, Schedule 4 for an overview of Remotes' project approval process.

The financial plan is prepared, incorporating OM&A and capital work program levels consistent with the investment plan, as well as forecasts of revenue, fuel, depreciation and amortization expense, financing charges, income tax, and working capital.

The resulting plan is reviewed by Remotes' Board. As necessary, underlying assumptions are modified and the results finalized and presented for approval of the consolidated plan to the Hydro One Board of Directors. The 2017-2022 Budget and Outlook was approved by the Board of Directors at its December 2017 meeting and the updated plan was approved by the Board of Directors at its January 2018 meeting.

# PROJECT AND PROGRAM APPROVAL AND CONTROL

## 1.0 INTRODUCTION

As described in Exhibit A, Tab 7, Schedule 3, there are a number of key steps within the overall business planning cycle that are typically completed prior to the development of the detailed project and program assessments. These prerequisite steps include needs identification, project/program prioritization and the development of preliminary work programs, based on estimates of project and program costs and benefits.

## 2.0 PROJECT AND PROGRAM APPROVAL

Once the preliminary plans have been accepted at the proof-of-concept stage, an analysis of costs, proposed accomplishments, benefits and risk is completed for each program and for individual projects.

For work programs of an ongoing nature (such as engine replacements), the analysis associated with each program are included in Asset Planning Documents for review and approval. Programs are reviewed annually, considering factors such as regulatory requirements, business efficiencies, impacts on customers, reliability, environment and safety along with any other relevant information. For specific improvement and facilities projects business cases are only completed during the detailed budgeting process in November of each year, when specific project scope can be determined.

For projects that are not routine and do not occur annually, Business Case Summaries ("BCS") for individual project proposals are developed and assessed. Similar analysis is undertaken for these projects, but in more detail than for routine work. Factors such as the need for the investment including the implications of not doing the work, the anticipated results and the recommended solution and its cost are all considered. In determining the recommended solution, alternative approaches and project risks are considered. The factors considered include regulatory requirements, business efficiencies, impacts on customers, reliability, environment and safety and any other relevant information. The proposals are reviewed in a series of steps at the senior management and executive levels, depending on the dollar limit and the significance of the investment. The proposals are then approved consistent with the provisions of the Expenditure Authority Register ("EAR"), described in Exhibit A, Tab 6, Schedule 2. For programs, this analysis and approval is completed as part of the investment planning process. Strategic investments are reviewed and approved by the Hydro One Board of Directors. The BCS documents provided in the Distribution System Plan summarize the proposed projects and programs with expenditures exceeding $283 thousand in the test year.

Projects funded by INAC are all subject to the Hydro One internal approvals described above. INAC-funded projects must also be approved by the local Band Council, and are also approved following INAC's own internal funding processes. INAC's funding processes consider alternative solutions, impacts on communities, and are reviewed and approved in a series of steps at INAC's senior management/executive level. Depending on the scale of the project, INAC-funded projects are subject to different steps, including design approval, Requests for Proposals and monthly monitoring by INAC and the individual First Nation. INAC-funded projects are described in more detail in the DSP, in Exhibit B.

## 3.0 MONITORING AND CONTROL

Each month, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures and work accomplishments. Deviations from plan are identified and corrective action taken.

In the event that significant changes in cost, schedule and/or scope of a project is forecasted, an Interim Review of Variance ("IROV") is prepared. An IROV is essentially an amended business case that is reviewed and approved based on the revised set of circumstances (cost, scope or schedule). The IROV approval is in accordance with the limits set out in the EAR. Projects which cannot be re-justified are either scaled back, cancelled or otherwise adjusted to conform to the new situation.

# ACCOUNTING INFORMATION

## 1.0 ACCOUNTING STANDARD

On April 3, 2012, the Board issued its Decision with Reasons in EB-2011-0427, granting Remotes' request to use United States Generally Accepted Accounting Principles for regulatory purposes. Based on this decision, Remotes adopted this accounting standard for regulatory purposes.

Remotes confirms that its accounting treatment segregates any non-utility business it conducts from its rate-regulated activities.

## 2.0 CHANGES TO ACCOUNTING POLICIES

In keeping with good corporate governance, Hydro One reviews and, if appropriate, revises its policies and procedures from time to time. These policies are applicable to Remotes. No financial accounting policy changes have been made that impact the 2018-2022 rate base or revenue requirement since the Board's review of Remotes' distribution revenue requirements and rates for 2013-2017 (EB-2012-0137) other than as specified in this section.

On November 5, 2015, Hydro One adopted "Accounting Standards Codification 718 – Compensation – Stock Compensation" to address the accounting of stock-based compensation. Adoption of this accounting policy has no impact on revenue requirement.

According to this policy, Hydro One measures share grant plans based on the fair value of the grants, which is determined by the share price on the grant date. 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. Hydro One records a regulatory asset equal to the accrued costs of share grant plans recognized in each period, as management considers it probable that such costs will be recovered in rates in the future.

# FINANCIAL SUMMARY

## 1.0 INTRODUCTION

Remotes is making this application in accordance with the requirements of the Ontario Energy Board *Filing Requirements for Transmission and Distribution Applications* issued November 14, 2006, and updated on July 14, 2016. The proposed revenue requirement and rates included in this Application have been prepared on the basis of a forward-looking 2018 test year. This submission also includes information for a 2017 bridge year, historical information for 2013, 2014, 2015 and 2016, and Board-approved information for 2013. Given that Remotes' previous Cost of Service rate submission was based on a 2013 test year, there is a five-year timing difference between test years. This timing lag should be kept in mind when making comparisons.

Remotes is proposing to recover a total revenue requirement of $56,689K: $17,612K from its customers (1.80% rate increase over 2017 rates), $999K from other revenues, and $38,078K from the Rural and Remote Rate Protection (RRRP) fund for the 2018 test year. Calculation of the revenue requirement appears in the evidence at Exhibit G2, Tab 1, Schedule 1.

Remotes' Operations, Maintenance and Administration ("OM&A") expenditures have been determined on the basis of an examination of required work programs to ensure that appropriate and cost-effective solutions are implemented. A description of Remotes' planning process is provided at Exhibit A, Tab 14, Schedule 1. The proposed OM&A expenditures are $50,143K and include $27,600K for diesel fuel required to generate electricity.

The overall proposed OM&A expenditures are driven by the need to meet customer, regulatory and statutory requirements regarding service and reliability as well as to repair, maintain and replace aging assets. These expenditures are itemized at Exhibit 2, Tab 1, Schedule 1 and discussed in written direct evidence at Exhibit E1, Tab 1, Schedule 1.

Remotes' proposed Rate Base of $44,445K is discussed at Exhibit C1, Tab 1, Schedule 1.

Remotes has calculated working capital based on the formula-based methodology described in the Board's Filing Guidelines for Transmitters and Distributors issued July 14, 2017. The calculation of working capital, filed at Exhibit C2, Tab 5, Schedule 1, incorporates generation-related OM&A accounts as Remotes provides integrated generation and distribution services.

Depreciation expense for Remotes' submission for the 2018 revenue requirement is based on the methodology in an independent study conducted by Foster Associates in 2012 and approved in EB-2012-0137. Depreciation expense of $3,576K has been determined based on this study. These costs are described in written evidence at Exhibit D1, Tab 6, Schedule 1 and shown in detail in Exhibit D2, Tab 7, Schedule 1.

Remotes recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. Consistent with the Board Decision in EB-2012-0137, this regulatory asset is amortized consistent with the actual expenditures incurred each year. Remotes forecasts assessment and remediation costs of $1,032K in the 2018 Test Year. Land Assessment and Remediation is discussed in Exhibit E1, Tab 6, Schedule 1.

Remotes is 100% debt-financed, consisting of 4% deemed short-term debt and 96% long-term debt. Remotes' evidence in support of its cost of capital appears at Exhibit E1, Tab 1, Schedule 1.

Under the terms of the Electrification Agreements, INAC is responsible for funding generation capital upgrades and service connections associated with load growth in the First Nations Communities served by Remotes. Remotes is responsible for funding capital replacements, and for capital improvements not associated with load growth. The requested revenue requirement reflects the costs, net of expected capital contributions from INAC, for Remotes' plan to invest in generation and distribution assets to meet its objectives regarding public and employee safety; environmental responsibility; regulatory and legislative compliance; and service quality and reliability. The capital project and program approval and control policy is presented at Exhibit A, Tab 7, Schedule 4. Remotes is forecasting total capital expenditures of $3,236K, net of contributed capital. Details of Remotes' capital budget are illustrated in schedules filed in the DSP at Exhibit B1, Tab 1, Schedule 1, Section 4.1.2.

Remotes receives less than 6% of its revenues from external sources ($999K in 2018). External revenues are discussed at Exhibit G1, Tab 3, Schedule 1.

Rural and Remote Rate Protection for customers in Remotes' service area is currently set at $32,259K per year. Remotes is requesting to increase annual RRRP revenue subsidies to $38,078K.

In accordance with standard regulatory practice, Remotes has incurred prior costs for which it is requesting approval in this submission. The December 2016 audited Rural and Remote Rate Protection Variance balance is $1,644K and is primarily related to increased diesel fuel costs and required maintenance. Remotes is proposing to recover $962K in the

2018 test year, which is the audited 2016 Rural and Remote Rate Protection Variance balance of $1,644K, offset by a 2017 income tax adjustment of $682K as described in Exhibit D1, Tab 7, Schedule 1, resulting in a total RRRP amount of $39,040K. Remotes' submission regarding these account balances and proposed disposition appears at Exhibit H1, Tab 1, Schedule 1.

Appendix 2-Y: Summary of Impacts to Revenue Requirement from Transition to MIFRS does not apply as Hydro One, including Remotes, moved to US GAAP.

# HYDRO ONE REMOTES FINANCIAL STATEMENT
# HISTORIC YEARS (2013, 2014, 2015 AND 2016)

Attachment 1: Hydro One Remote Communities Inc. Financial Statements 2013
Attachment 2: Hydro One Remote Communities Inc. Financial Statements 2014
Attachment 3: Hydro One Remote Communities Inc. Financial Statements 2015
Attachment 4: Hydro One Remote Communities Inc. Financial Statements 2016

# HYDRO ONE REMOTE COMMUNITIES INC.

## FINANCIAL STATEMENTS

## DECEMBER 31, 2013

**HYDRO ONE REMOTE COMMUNITIES INC.**
**INDEPENDENT AUDITORS' REPORT**

To Directors of Hydro One Remote Communities Inc.

We have audited the accompanying financial statements of Hydro One Remote Communities Inc., which comprise the balance sheet as at December 31, 2013, the statements of operations and comprehensive income, changes in shareholder's deficit and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these 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 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 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 Hydro One Remote Communities Inc. as at December 31, 2013, and its results of operations and its cash flows for the year then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 26, 2014

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**
**For the years ended December 31, 2013 and 2012**

| *Year ended December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| **Revenues** *(Note 15)* | 50,035 | 46,766 |
| **Costs** | | |
| Operation, maintenance and administration *(Note 15)* | 19,645 | 16,861 |
| Fuel used for electric generation | 25,568 | 24,306 |
| Depreciation and amortization *(Note 4)* | 4,809 | 6,019 |
| | 50,022 | 47,186 |
| **Income (loss) before financing charges and recovery of payments in lieu of corporate income taxes** | 13 | (420) |
| Financing charges *(Notes 5, 15)* | 1,104 | 1,016 |
| **Loss before recovery of payments in lieu of corporate income taxes** | (1,091) | (1,436) |
| Recovery of payments in lieu of corporate income taxes *(Notes 6, 15)* | (1,091) | (1,436) |
| **Net income** | – | – |
| Other comprehensive income | 13 | 12 |
| **Comprehensive income** | 13 | 12 |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS**
**At December 31, 2013 and 2012**

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Accounts receivable (net of allowance for doubtful accounts – $296; 2012 – $297) *(Notes 7, 15)* | 4,995 | 4,193 |
| Regulatory assets *(Note 9)* | 2,427 | 1,823 |
| Fuel, materials and supplies | 1,736 | 2,179 |
| Deferred income tax assets *(Note 6)* | 108 | 108 |
| Income tax receivable *(Notes 6, 15)* | 2,697 | 1,589 |
| | 11,963 | 9,892 |
| Property, plant and equipment *(Note 8)*: | | |
| Property, plant and equipment in service | 58,905 | 54,790 |
| Less: accumulated depreciation | 23,256 | 25,779 |
| | 35,649 | 29,011 |
| Construction in progress | 3,473 | 7,250 |
| Future use components and spares | 1,650 | 1,573 |
| | 40,772 | 37,834 |
| Other long-term assets: | | |
| Regulatory assets *(Note 9)* | 15,923 | 14,060 |
| Deferred income tax assets *(Note 6)* | 4,239 | 4,733 |
| Deferred debt costs *(Note 10)* | 124 | 128 |
| Long-term accounts receivable (net of allowance for doubtful accounts – $0; 2012 – $5) *(Note 7)* | 674 | 418 |
| | 20,960 | 19,339 |
| **Total assets** | 73,695 | 67,065 |

*See accompanying notes to Financial Statements.*

## HYDRO ONE REMOTE COMMUNITIES INC.
## BALANCE SHEETS (continued)
### At December 31, 2013 and 2012

| *December 31 (thousands of dollars ,except number of shares)* | **2013** | **2012** |
|---|---|---|
| **Liabilities** | | |
| Current liabilities: | | |
| Inter-company demand facility *(Notes 11, 15)* | 18,031 | 11,212 |
| Accounts payable | 703 | 987 |
| Accrued liabilities *(Notes 12, 13)* | 4,954 | 5,876 |
| Accrued interest *(Note 15)* | 142 | 142 |
| Regulatory liabilities *(Note 9)* | 109 | 108 |
| | 23,939 | 18,325 |
| Long-term debt *(Notes 10, 11, 15)* | 23,000 | 23,000 |
| Other long-term liabilities: | | |
| Post-retirement and post-employment benefit liability *(Note 12)* | 12,088 | 11,532 |
| Regulatory liabilities *(Note 9)* | 4,238 | 4,733 |
| Environmental liabilities *(Note 13)* | 10,999 | 10,057 |
| | 27,325 | 26,322 |
| **Total liabilities** | 74,264 | 67,647 |
| *Contingencies and commitments (Notes 17, 18)* | | |
| **Shareholder's deficit** | | |
| Common shares (authorized: unlimited; issued: 2) *(Note 14)* | – | – |
| Accumulated other comprehensive loss | (569) | (582) |
| **Total shareholder's deficit** | (569) | (582) |
| **Total liabilities and shareholder's deficit** | 73,695 | 67,065 |

*See accompanying notes to Financial Statements.*

On behalf of the Board of Directors:

Carmine Marcello
Chair

Lee Ann Cameron
Director

## HYDRO ONE REMOTE COMMUNITIES INC.
## STATEMENTS OF CHANGES IN SHAREHOLDER'S DEFICIT
**For the years ended December 31, 2013 and 2012**

| *Year ended December 31, 2013* *(thousands of dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2013 | – | (582) | (582) |
| Other comprehensive income | – | 13 | 13 |
| **December 31, 2013** | – | (569) | (569) |

| *Year ended December 31, 2012* *(thousands of dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2012 | – | (594) | (594) |
| Other comprehensive income | – | 12 | 12 |
| **December 31, 2012** | – | (582) | (582) |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CASH FLOWS**
**For the years ended December 31, 2013 and 2012**

| *Year ended December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| **Operating activities** | | |
| Net income | – | – |
| Environmental expenditures | (1,656) | (2,515) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (excluding removal costs) | 4,220 | 5,461 |
| Regulatory assets and liabilities | (1,126) | (3,957) |
| Amortization of hedging losses | 13 | 12 |
| Amortization of deferred debt costs and debt discounts | 3 | 2 |
| Gain on disposition of property, plant and equipment | – | (2) |
| Changes in non-cash balances related to operations *(Note 16)* | (2,773) | (947) |
| **Net cash used in operating activities** | (1,319) | (1,946) |
| **Investing activities** | | |
| Capital expenditures | (5,427) | (7,042) |
| Proceeds on disposition of property, plant and equipment | 4 | 11 |
| Future use assets | (77) | (23) |
| **Net cash used in investing activities** | (5,500) | (7,054) |
| **Net change in inter-company demand facility** | (6,819) | (9,000) |
| Inter-company demand facility, beginning of year | (11,212) | (2,212) |
| **Inter-company demand facility, end of year** | (18,031) | (11,212) |

*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 Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario), and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province’s electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The Company uses a cost recovery model applied to achieve breakeven net income and are for the specific use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2013 have been prepared and are publicly available.

Hydro One Remote Communities 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. No such events or transactions were identified.

### Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairment, contingencies, unbilled revenue, allowance for doubtful accounts 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

On April 3, 2012, the OEB approved the Company’s request to use US GAAP as the basis for rate setting and regulatory accounting and reporting, effective January 1, 2012.

In November 2011, Hydro One Remote Communities filed an Incentive Regulation Mechanism (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 for 2013 distribution rates. The application requested an increase of 3.45% to customer rates for generation and distribution and an increase of approximately $7 million to annual Rural and Remote Rate Protection (RRRP). In September, 2013, the OEB approved the proposed rate increase and annual RRRP of approximately $32.3 million.

### Regulatory Accounting

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

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of the recovery of / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in RRRP amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

### Revenue Recognition

Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues attributable to the generation and 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 RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

### Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount and overdue amounts related to regulated billings bear interest at OEB approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 120 days from the bill due 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 Remote Communities is required to make (recover) PILs to (from) 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 Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

***Current Income Taxes***

The recovery of or 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 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.

**Inter-company Demand Facility**

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash 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%.

**Fuel, Materials and Supplies**

Fuel is used in the generation of electricity. 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

#### *Generation*

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

#### *Distribution*

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

#### *Administration and Service*

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

### Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 in Progress

Construction 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

The cost of property, plant and equipment is depreciated 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 depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 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 |
|---|---|---|---|
| Generation | 22 years | 3% – 7% | 5% |
| Distribution | 36 years | 1% – 7% | 3% |
| Administration and service | 20 years | 3% – 20% | 3% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 assets where no asset retirement obligation 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 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. 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 the 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 rate 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents OCI and net income 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.

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 11 – Fair Value of Financial Instruments and Risk Management.

Transaction costs associated with financial assets and liabilities that are designated as held-for-trading are recognized immediately in results of operations. All financial instrument transactions are recorded at trade date.

**Derivative Instruments and Hedge Accounting**

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2013. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

**Employee Future Benefits**

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

Hydro One recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment funds are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets 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, including Hydro One Remote Communities, but not including Hydro One Brampton Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit 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***

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of the these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's 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 accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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 Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its 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. 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 Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement 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 Remote Communities records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 Remote

Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

## 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 and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on its financial position. This ASU 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 Company's 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 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 Financial Statements.

## 4. DEPRECIATION AND AMORTIZATION

| *Year ended December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Depreciation of property, plant and equipment | 2,564 | 2,946 |
| Asset removal costs | 589 | 560 |
| Gain on disposition of property, plant and equipment | – | (2) |
| Amortization of regulatory assets | 1,656 | 2,515 |
| | 4,809 | 6,019 |

## 5. FINANCING CHARGES

| *Year ended December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Interest on long-term debt | 1,237 | 1,237 |
| Interest on inter-company demand facility | 216 | 83 |
| Amortization of hedging losses | 13 | 12 |
| Other | 14 | 5 |
| Less: Interest capitalized on construction in progress | (376) | (321) |
| | 1,104 | 1,016 |

## 6. PROVISION FOR PILS

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 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Loss before recovery of PILs | (1,091) | (1,436) |
| Canadian Federal and Ontario statutory income tax rate | 26.50% | 26.50% |
| Recovery of PILs at statutory rate | (289) | (381) |
| | | |
| Increase (decrease) resulting from: | | |
| | | |
| Net temporary differences included in amounts charged to customers: | | |
| Depreciation and amortization in excess of capital cost allowance | 469 | 913 |
| Environmental expenditures | (439) | (667) |
| Overheads capitalized for accounting but deducted for tax purposes | (82) | (102) |
| Interest capitalized for accounting but deducted for tax purposes | (100) | (85) |
| Post-retirement and post-employment benefit expense in excess of cash payments | 135 | 74 |
| RRPR variance account | (318) | (1,029) |
| Pension contribution in excess of pension expense | (90) | (107) |
| Other | 56 | (15) |
| Net temporary differences | (369) | (1,018) |
| Prior year adjustments | (332) | – |
| Rate difference on loss carryback | (110) | – |
| Other permanent differences | 9 | (37) |
| Total recovery of PILs | (1,091) | (1,436) |
| | | |
| Current recovery of PILs | (1,091) | (1,436) |
| Deferred recovery of PILs | – | – |
| Total recovery of PILs | (1,091) | (1,436) |
| | | |
| Effective income tax rate | 100% | 100% |

The recovery of payments in lieu of current income taxes of $1,091 thousand (2012 – $1,436 thousand) represents the amount that is recoverable from the OEFC with respect to current year income. The balance receivable from the OEFC at December 31, 2013 was $2,697 thousand (2012 – $1,589 thousand).

**Deferred Income Tax Assets**

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 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| **Deferred income tax assets** | | |
| Environmental expenditures | 4,840 | 4,283 |
| Post-retirement and post-employment benefits expense in excess of cash payments | 4,466 | 4,266 |
| Depreciation and amortization in excess of capital cost allowance | 1,845 | 2,263 |
| Regulatory amounts not recognized for tax | (6,615) | (5,726) |
| Debt costs and hedging losses recognized for tax but not for accounting purposes | (189) | (245) |
| Total deferred income tax assets | 4,347 | 4,841 |
| Less: current portion | 108 | 108 |
| | 4,239 | 4,733 |

During 2013, there was no change in the rate applicable to future taxes (2012 – a change in rate applicable to future rates resulted in a $464 thousand increase to deferred tax liability).

## 7. ACCOUNTS RECEIVABLE

| *December 31 (thousands of dollars)* | Current accounts receivable | Long-term accounts receivable | Total |
|---|---|---|---|
| **2013** | | | |
| Accounts receivable – billed | 3,887 | 674 | 4,561 |
| Accounts receivable – unbilled | 1,404 | – | 1,404 |
| Accounts receivable, gross | 5,291 | 674 | 5,965 |
| Allowance for doubtful accounts | (296) | – | (296) |
| Accounts receivable, net | 4,995 | 674 | 5,669 |
| | | | |
| **2012** | | | |
| Accounts receivable – billed | 2,963 | 423 | 3,386 |
| Accounts receivable – unbilled | 1,527 | – | 1,527 |
| Accounts receivable, gross | 4,490 | 423 | 4,913 |
| Allowance for doubtful accounts | (297) | (5) | (302) |
| Accounts receivable, net | 4,193 | 418 | 4,611 |

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2013 and 2012:

| *Year ended December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Allowance for doubtful accounts – January 1 | (302) | (658) |
| Write-offs | 95 | 222 |
| Adjustments to allowance for doubtful accounts | (89) | 134 |
| Allowance for doubtful accounts – December 31 | (296) | (302) |

## 8. PROPERTY, PLANT AND EQUIPMENT

| *December 31 (thousands of dollars)* | Costs | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| **2013** | | | | |
| Generation | 41,616 | 19,517 | 2,716 | 24,815 |
| Distribution | 8,394 | 1,748 | 596 | 7,242 |
| Administration and Service | 10,545 | 1,991 | 161 | 8,715 |
| | 60,555 | 23,256 | 3,473 | 40,772 |
| **2012** | | | | |
| Generation | 38,803 | 22,056 | 6,764 | 23,511 |
| Distribution | 7,757 | 1,785 | 315 | 6,287 |
| Administration and Service | 9,803 | 1,938 | 171 | 8,036 |
| | 56,363 | 25,779 | 7,250 | 37,834 |

Financing charges capitalized on property, plant and equipment under construction were $376 thousand in 2013 (2012 – $321 thousand).

## 9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| **Regulatory assets:** | | |
| Environmental | 13,426 | 11,880 |
| Post-retirement and post-employment benefits | 2,939 | 3,144 |
| RRPR variance account | 1,985 | 787 |
| IFRS transition cost variance | – | 72 |
| Total regulatory assets | 18,350 | 15,883 |
| Less: current portion | 2,427 | 1,823 |
| | 15,923 | 14,060 |
| **Regulatory liabilities:** | | |
| Deferred income tax regulatory liability | 4,347 | 4,841 |
| Total regulatory liabilities | 4,347 | 4,841 |
| Less: current portion | 108 | 108 |
| | 4,239 | 4,733 |

### Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. Management considers it probable that such expenditures will be recovered in the future through the rate-setting process, and as such, the Company has recorded an equivalent amount as a regulatory asset. In 2013, this regulatory asset increased by $2,872 thousand (2012 – decreased by $583 thousand) to reflect related changes in the Company’s environmental liabilities. 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 Company’s actual environmental expenditures. In the absence of rate-regulated accounting, 2013 operation, maintenance and administration expenses would have been higher by $2,872 thousand (2012 – lower by $583 thousand). In addition, 2013 amortization expense would have been lower by $1,656 thousand (2012 – $2,515 thousand), and 2013 financing charges would have been higher by $330 thousand (2012 – $399 thousand).

**Post-Retirement and Post-Employment Benefits**

The Company 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 $205 thousand (2012 – lower by $1,941 thousand).

**RRPR Variance Account**

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2013, the Company has recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of net RRRP amounts received. At December 31, 2012, net RRRP amounts received were also lower than amounts required to achieve breakeven net income, and as such, a regulatory asset was also recognized. In the absence of rate-regulated accounting, 2013 revenue would have been lower by $1,198 thousand (2012 – $3,957 thousand).

**IFRS Transition Costs Variance**

Hydro One Remote Communities recorded an asset for the variance between its one-time incremental costs incurred in its uncompleted transition to IFRS and amounts included in rates in respect of this project. In 2013, the company decided not to seek recovery of this amount from rate payers and it was included in the Statement of Operations.

**Deferred Income Tax Regulatory 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 recovery of PILs would have been lower by approximately $367 thousand (2012 – $771 thousand).

## 10. LONG-TERM DEBT

Long-term debt represents a note payable to Hydro One. The note was issued on May 19, 2005, with a carrying value of $23,000 thousand and interest at a rate of 5.38% per annum. The note matures on May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999 in consideration of the purchase price of Hydro One Remote Communities' net assets.

On issuance of this note, $115 thousand of transaction costs and a $31 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

## 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.

Hydro One Remote Communities 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 Remote Communities 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 Company's 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 Hierarchy**

The fair value hierarchy of financial assets and liabilities at December 31, 2013 and 2012 are as follows:

| *December 31, 2013 (thousands of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 18,031 | 18,031 | 18,031 | – | – |
| Long-term debt | 23,000 | 25,450 | – | 25,450 | – |
| | 41,031 | 43,481 | 18,031 | 25,450 | – |

| *December 31, 2012 (thousands of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 11,212 | 11,212 | 11,212 | – | – |
| Long-term debt | 23,000 | 28,486 | – | 28,486 | – |
| | 34,212 | 39,698 | 11,212 | 28,486 | – |

The fair value 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 foreign exchange risk is currently not significant, although Hydro One could in the future decide to issue and allocate foreign currency-denominated debt to the Company, along with an allocation of the resulting foreign exchange gains and losses. The Company is exposed to fluctuations in interest rates related

to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the bankers' acceptance rate, plus 0.15%.

***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 Remote Communities 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 Company's total provision for bad debts was $296 thousand (2012 – $302 thousand). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2013, approximately 47% of the Company's current accounts receivable were aged more than 60 days (2012 – 34%). Sufficient allowances have been recorded to reflect the risk of potential credit losses.

***Liquidity Risk***

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities 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 $5,657 thousand (2012 – $6,863 thousand) are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2013, Hydro One Remote Communities had long-term debt in the principal l amount of $23,000 thousand (2012 – $23,000 thousand). No long-term debt matures during the next year. Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $1,237 thousand (2012 – $1,237 thousand). Principal repayments and interest payments are summarized by the number of years to maturity in the following table.

| **Years to Maturity** | **Principal Outstanding on Long-term Debt** *(thousands of dollars)* | **Interest Payments** *(thousands of dollars)* |
|---|---|---|
| 1 year | – | 1,237 |
| 2 years | – | 1,237 |
| 3 years | – | 1,237 |
| 4 years | – | 1,237 |
| 5 years | – | 1,237 |
| | – | 6,185 |
| 6 – 10 years | – | 6,185 |
| Over 10 years | 23,000 | 15,468 |
| | 23,000 | 27,838 |

## 12. 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. 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 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.

Company and employees' 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, Hydro One Remote Communities charged $775 thousand (2012 – $537 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $250 thousand (2012 – $223 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2013 were $264 thousand (2012 – $259 thousand). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $205 thousand (2012 – increased by $1,941 thousand) and recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Accrued liabilities | 300 | 300 |
| Post-retirement and post-employment benefit liability | 12,088 | 11,532 |
| | 12,388 | 11,832 |

## 13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2013 and 2012:

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Environmental liabilities, January 1 | 11,880 | 14,579 |
| Interest accretion | 330 | 399 |
| Expenditures | (1,656) | (2,515) |
| Revaluation adjustment | 2,872 | (583) |
| Environmental liabilities, December 31 | 13,426 | 11,880 |
| Less: current portion | 2,427 | 1,823 |
| | 10,999 | 10,057 |

The following table illustrates 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 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Undiscounted environmental liabilities, December 31 | 14,014 | 12,503 |
| Less: discounting accumulated liabilities to present value | 588 | 623 |
| Discounted environmental liabilities, December 31 | 13,426 | 11,880 |

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2013 and in total thereafter are as follows: 2014 – $2,427 thousand; 2015 – $2,175 thousand; 2016 – $2,844 thousand; 2017 – $1,261 thousand; 2018 – $1,651 thousand; and thereafter – $3,653 thousand. These expenditures are expected to be incurred over the period from 2014 to 2020.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting its expectation that future environmental costs will be recoverable in rates.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.57% to 4.87%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

As a result of its annual review of the environmental liabilities, the Company recorded a revaluation adjustment to increase the LAR environmental liability by $2,872 thousand (2012 – decrease by $583 thousand).

## 14. SHARE CAPITAL

### Common Shares

The Company has 2 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

### Dividends

The Company has no retained earnings and does not pay dividends under its breakeven business model.

## 15. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities 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 Hydro One Remote Communities because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One Remote Communities are described below.

Hydro One Remote Communities receives amounts for RRRP from the IESO. RRRP amounts received for the year ended December 31, 2013 were $33,046 thousand (2012 – $27,549 thousand). Consistent with its breakeven business model, the Company recognized $34,245 thousand as RRRP revenue in 2013 (2012 – $31,506 thousand). This 2013 revenue exceeded

amounts received by $1,199 thousand (2012 – $3,957 thousand) and the RRPR variance account balance was adjusted by this amount.

The recovery of PILs was received or receivable from the OEFC.

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

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Accounts receivable | 97 | 88 |
| Income tax receivable | 2,697 | 1,589 |

Transactions with 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.

**Hydro One and Subsidiaries**

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its other 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 corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2013 revenues include $195 thousand (2012 – $130 thousand) related to the provision of services to Hydro One and its other subsidiaries. 2013 operation, maintenance and administration costs include $3,475 thousand (2012 – $2,607 thousand) related to the purchase of services from Hydro One and its other subsidiaries.

The Company's long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One and its other subsidiaries. Financing charges include interest expense on the long-term debt in the amount of $1,237 thousand (2012 – $1,237 thousand), and interest expense on the inter-company demand facility in the amount of $216 thousand (2012 – $83 thousand). At December 31, 2013, the Company had accrued interest payable to Hydro One totaling $142 thousand (2012 – $142 thousand).

## 16. STATEMENTS OF CASH FLOWS

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

| *Year ended December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Accounts receivable | (802) | (258) |
| Materials and supplies | 443 | 638 |
| Income taxes receivable | (1,108) | (1,426) |
| Long-term accounts receivable | (256) | (49) |
| Accounts payable | (284) | (443) |
| Accrued liabilities | (1,526) | 91 |
| Post-retirement and post-employment benefit liability | 760 | 500 |
| | (2,773) | (947) |

| **Supplementary information:** | | |
|---|---|---|
| Net interest paid | 1,453 | 1,320 |

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any PILs paid are fully recovered.

## 17. CONTINGENCIES

### Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

### Transfer of Assets

The transfer orders by which the Company acquired Ontario Hydro's remote communities business on April 1, 1999 did not transfer title to some assets located on lands held for First Nation bands under the *Indian Act* (Canada). Currently, OEFC holds legal title to these assets and the Company manages them until the Company has obtained necessary authorizations to complete the title transfer. To occupy reserve land, 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 band, OEFC and any First Nation individuals who have occupancy rights. The agreement includes provisions whereby the First Nation band consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. 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 the First Nation bands. In 2013, the Company paid approximately $2 million (2012 – $1 million) in respect of these consents. OEFC will continue to hold these assets until the Company is able to negotiate agreements with the First Nation bands and occupants. If the Company cannot reach satisfactory agreements and obtain federal permits, the Company may have to relocate these assets from the reserve lands to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on the Company's net income if the Company is not able to recover them in future rate orders.

## 18. COMMITMENTS

### Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years.

At December 31, 2013, the future minimum lease payments under this operating lease are as follows:

| *Year ended December 31 (thousands of dollars)* | **2013** |
|---|---|
| Within one year | 120 |
| After one year but not more than five years | 510 |
| More than five years | 600 |
| | 1,230 |

During the year ended December 31, 2013, the Company made upfront lease payments totalling $1 million which is being amortized based over the contractual term of the lease.

# HYDRO ONE REMOTE COMMUNITIES INC.

## FINANCIAL STATEMENTS

## DECEMBER 31, 2014

**HYDRO ONE REMOTE COMMUNITIES INC.**
**INDEPENDENT AUDITORS' REPORT**

To Directors of Hydro One Remote Communities Inc.

We have audited the accompanying financial statements of Hydro One Remote Communities Inc., which comprise the balance sheet as at December 31, 2014, the statements of operations and comprehensive income, changes in shareholder's deficit and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these 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 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 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 Hydro One Remote Communities Inc. as at December 31, 2014, and its results of operations and its cash flows for the year then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
March 24, 2015

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**
**For the years ended December 31, 2014 and 2013**

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Revenues** *(Note 15)* | 52,130 | 50,035 |
| **Costs** | | |
| Operation, maintenance and administration *(Note 15)* | 20,069 | 19,645 |
| Fuel used for electric generation | 25,869 | 25,568 |
| Depreciation and amortization *(Note 4)* | 4,623 | 4,809 |
| | 50,561 | 50,022 |
| **Income (loss) before financing charges and recovery of payments in lieu of corporate income taxes** | 1,569 | 13 |
| Financing charges *(Notes 5, 15)* | 1,559 | 1,104 |
| **Income before recovery of payments in lieu of corporate income taxes** | 10 | (1,091) |
| Provision for (recovery of) payments in lieu of corporate income taxes *(Notes 6, 15)* | 10 | (1,091) |
| **Net income** | – | – |
| Other comprehensive income | 13 | 13 |
| **Comprehensive income** | 13 | 13 |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS**
**At December 31, 2014 and 2013**

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Accounts receivable (net of allowance for doubtful accounts – $145; 2013 – $296) *(Notes 7, 15)* | 4,454 | 4,995 |
| Regulatory assets *(Note 9)* | 1,301 | 2,427 |
| Fuel, materials and supplies | 2,092 | 1,736 |
| Deferred income tax assets *(Note 6)* | 120 | 108 |
| Income tax receivable *(Notes 6, 15)* | 2,683 | 2,697 |
| | 10,650 | 11,963 |
| Property, plant and equipment *(Note 8)*: | | |
| Property, plant and equipment in service | 63,601 | 58,905 |
| Less: accumulated depreciation | 24,588 | 23,256 |
| | 39,013 | 35,649 |
| Construction in progress | 2,138 | 3,473 |
| Future use components and spares | 1,767 | 1,650 |
| | 42,918 | 40,772 |
| Other long-term assets: | | |
| Regulatory assets *(Note 9)* | 18,283 | 15,923 |
| Deferred income tax assets *(Note 6)* | 4,213 | 4,239 |
| Deferred debt issuance costs *(Note 10)* | 183 | 124 |
| Long-term accounts receivable (net of allowance for doubtful accounts – $159; 2013 – $0) *(Note 7)* | 1,250 | 674 |
| | 23,929 | 20,960 |
| **Total assets** | 77,497 | 73,695 |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS (continued)**
**At December 31, 2014 and 2013**

| *December 31 (thousands of Canadian dollars, except number of shares)* | **2014** | **2013** |
|---|---|---|
| **Liabilities** | | |
| Current liabilities: | | |
| Inter-company demand facility *(Notes 11, 15)* | 6,806 | 18,031 |
| Accounts payable | 876 | 703 |
| Accrued liabilities *(Notes 12, 13)* | 8,936 | 4,954 |
| Accrued interest *(Note 15)* | 172 | 142 |
| Regulatory liabilities *(Note 9)* | 120 | 109 |
| | 16,910 | 23,939 |
| Long-term debt *(Notes 10, 11, 15)* | 33,000 | 23,000 |
| Other long-term liabilities: | | |
| Post-retirement and post-employment benefit liability *(Note 12)* | 12,862 | 12,088 |
| Regulatory liabilities *(Note 9)* | 4,213 | 4,238 |
| Environmental liabilities *(Note 13)* | 11,068 | 10,999 |
| | 28,143 | 27,325 |
| **Total liabilities** | 78,053 | 74,264 |
| *Contingencies and commitments (Notes 17, 18)* | | |
| **Shareholder's deficit** | | |
| Common shares (authorized: unlimited; issued: 2) *(Note 14)* | – | – |
| Accumulated other comprehensive loss | (556) | (569) |
| **Total shareholder's deficit** | (556) | (569) |
| **Total liabilities and shareholder's deficit** | 77,497 | 73,695 |

*See accompanying notes to Financial Statements.*

On behalf of the Board of Directors:

Carmine Marcello
Chair

Lee Ann Cameron
Director

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CHANGES IN SHAREHOLDER'S DEFICIT**
**For the years ended December 31, 2014 and 2013**

| *Year ended December 31, 2014* *(thousands of Canadian dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2014 | – | (569) | (569) |
| Other comprehensive income | – | 13 | 13 |
| **December 31, 2014** | – | (556) | (556) |

| *Year ended December 31, 2013* *(thousands of Canadian dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2013 | – | (582) | (582) |
| Other comprehensive income | – | 13 | 13 |
| **December 31, 2013** | – | (569) | (569) |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CASH FLOWS**
**For the years ended December 31, 2014 and 2013**

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Operating activities** | | |
| Net income | – | – |
| Environmental expenditures | (1,598) | (1,656) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (excluding removal costs) | 4,193 | 4,220 |
| Regulatory assets and liabilities | (2,594) | (1,126) |
| Amortization of hedging losses | 13 | 13 |
| Amortization of deferred debt costs and debt discounts | 3 | 3 |
| Changes in non-cash balances related to operations *(Note 16)* | 6,007 | (2,773) |
| **Net cash from (used in) operating activities** | 6,024 | (1,319) |
| **Financing activities** | | |
| Long-term debt issued | 10,000 | – |
| Other | (60) | – |
| **Net cash from financing activities** | 9,940 | – |
| **Investing activities** | | |
| Capital expenditures | (4,634) | (5,427) |
| Proceeds on disposition of property, plant and equipment | 12 | 4 |
| Future use assets | (117) | (77) |
| **Net cash used in investing activities** | (4,739) | (5,500) |
| **Net change in inter-company demand facility** | 11,225 | (6,819) |
| Inter-company demand facility, beginning of year | (18,031) | (11,212) |
| **Inter-company demand facility, end of year** | (6,806) | (18,031) |

*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 Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario), and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The Company uses a cost recovery model applied to achieve breakeven net income and the financial statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2014 have been prepared and are publicly available.

Hydro One Remote Communities 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. No such events or transactions were identified.

### Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairment, contingencies, unbilled revenue, allowance for doubtful accounts 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

In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 distribution rates, seeking approval for a rate increase of approximately 0.48%. On March 13, 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.

In 2012, Hydro One Remote Communities filed a cost-of-service application for 2013 distribution rates. The application requested an increase of 3.45% to customer rates for generation and distribution and an increase of approximately $7 million to annual Rural and Remote Rate Protection (RRRP). In 2013, the OEB approved the proposed rate increase and annual RRRP of approximately $32 million.

**Regulatory Accounting**

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

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of the recovery of / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in RRRP amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

**Revenue Recognition**

Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues attributable to the generation and 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 RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

**Accounts Receivable and Allowance for Doubtful Accounts**

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

Long-term accounts receivable are recorded at their invoiced amount and represent amounts due from specified First Nations. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. Provision for uncollectible amounts for this component is set at the inception of the balance and is maintained until settlement of those amounts. The provision for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts

receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

**Corporate Income Taxes**

Under the *Electricity Act, 1998*, Hydro One Remote Communities is required to make (recover) PILs to (from) 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 recovery of or 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 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.

**Inter-company Demand Facility**

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and

withdrawals made by the Company to and from the pooled cash 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%.

**Fuel, Materials and Supplies**

Fuel is used in the generation of electricity. 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

***Generation***

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

***Distribution***

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

***Administration and Service***

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

**Capitalized Financing Costs**

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 in Progress**

Construction 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

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category.

The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 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 |
|---|---|---|---|
| Generation | 22 years | 3% – 7% | 5% |
| Distribution | 48 years | 1% – 7% | 2% |
| Administration and service | 45 years | 2% – 20% | 4% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 assets where no asset retirement obligation 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 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. As at December 31, 2014, no asset impairment had been recorded.

### 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 Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents OCI and net income 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.

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 11 – Fair Value of Financial Instruments and Risk Management.

Transaction costs associated with financial assets and liabilities that are designated as held-for-trading are recognized immediately in results of operations. All financial instrument transactions are recorded at trade date.

**Derivative Instruments and Hedge Accounting**

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2014. OCI includes the amortization of net unamortized hedging losses on the Company’s proportionate share of Hydro One’s discontinued cash flow hedges.

**Employee Future Benefits**

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One’s 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 plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets 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 all 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, including Hydro One Remote Communities, but not including Hydro One Brampton Inc and Norfolk Power Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit 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***

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of the these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for

purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's 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 accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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 Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its 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. 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 Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement 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 Remote Communities records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

## 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 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 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 financial statements.

## 4. DEPRECIATION AND AMORTIZATION

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Depreciation of property, plant and equipment | 2,594 | 2,564 |
| Asset removal costs | 430 | 589 |
| Amortization of regulatory assets | 1,599 | 1,656 |
| | 4,623 | 4,809 |

## 5. FINANCING CHARGES

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Interest on long-term debt | 1,477 | 1,237 |
| Interest on inter-company demand facility | 187 | 216 |
| Amortization of hedging losses | 13 | 13 |
| Other | 28 | 14 |
| Less: Interest capitalized on construction in progress | (146) | (376) |
| | 1,559 | 1,104 |

## 6. PROVISION FOR PILS

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 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Income (loss) before provision for (recovery of) PILs | 10 | (1,091) |
| Canadian Federal and Ontario statutory income tax rate | 26.50% | 26.50% |
| Provision for (recovery of) PILs at statutory rate | 3 | (289) |
| | | |
| Increase (decrease) resulting from: | | |
| | | |
| Net temporary differences included in amounts charged to customers: | | |
| RRPR variance account | (687) | (318) |
| Environmental expenditures | (424) | (439) |
| Pension contribution in excess of pension expense | (132) | (90) |
| Overheads capitalized for accounting but deducted for tax purposes | (93) | (82) |
| Interest capitalized for accounting but deducted for tax purposes | (39) | (100) |
| Losses carryforward | 846 | – |
| Depreciation and amortization in excess of capital cost allowance | 338 | 469 |
| Post-retirement and post-employment benefit expense in excess of cash payments | 189 | 135 |
| Other | – | 56 |
| Net temporary differences | (2) | (369) |
| Prior year adjustments | 10 | (332) |
| Rate difference on loss carryback | – | (110) |
| Other permanent differences | (1) | 9 |
| Total provision for (recovery of) PILs | 10 | (1,091) |
| | | |
| Current provision for (recovery of) PILs | 10 | (1,091) |
| Deferred provision for (recovery of) PILs | – | – |
| Total provision for (recovery of) PILs | 10 | (1,091) |
| | | |
| Effective income tax rate | 100% | 100% |

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2014, the amount receivable from the OEFC was $2,683 thousand (2013 – $2,697 thousand).

**Deferred Income Tax Assets**

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, 2014 and 2013, deferred income tax assets and liabilities consisted of the following:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Deferred income tax assets** | | |
| Post-retirement and post-employment benefits expense in excess of cash payments | 4,762 | 4,466 |
| Environmental expenditures | 4,459 | 4,840 |
| Depreciation and amortization in excess of capital cost allowance | 1,231 | 1,845 |
| Non capital losses | 1,183 | – |
| Regulatory amounts not recognized for tax | (7,060) | (6,615) |
| Other | (242) | (189) |
| Total deferred income tax assets | 4,333 | 4,347 |
| Less: current portion | 120 | 108 |
| | 4,213 | 4,239 |

During 2014 and 2013, there was no change in the rate applicable to future taxes.

## 7. ACCOUNTS RECEIVABLE

| *December 31 (thousands of Canadian dollars)* | Current accounts receivable | Long-term accounts receivable | Total |
|---|---|---|---|
| **2014** | | | |
| Accounts receivable – billed | 3,214 | 1,409 | 4,623 |
| Accounts receivable – unbilled | 1,385 | – | 1,385 |
| Accounts receivable, gross | 4,599 | 1,409 | 6,008 |
| Allowance for doubtful accounts | (145) | (159) | (304) |
| Accounts receivable, net | 4,454 | 1,250 | 5,704 |
| | | | |
| **2013** | | | |
| Accounts receivable – billed | 3,887 | 674 | 4,561 |
| Accounts receivable – unbilled | 1,404 | – | 1,404 |
| Accounts receivable, gross | 5,291 | 674 | 5,965 |
| Allowance for doubtful accounts | (296) | – | (296) |
| Accounts receivable, net | 4,995 | 674 | 5,669 |

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2014 and 2013:

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Allowance for doubtful accounts – January 1 | (296) | (302) |
| Write-offs | 77 | 95 |
| Adjustments to allowance for doubtful accounts | (85) | (89) |
| Allowance for doubtful accounts – December 31 | (304) | (296) |

## 8. PROPERTY, PLANT AND EQUIPMENT

| *December 31 (thousands of Canadian dollars)* | Costs | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| **2014** | | | | |
| Generation | 44,770 | 20,385 | 1,742 | 26,127 |
| Distribution | 9,488 | 1,906 | 99 | 7,681 |
| Administration and Service | 11,110 | 2,297 | 297 | 9,110 |
| | 65,368 | 24,588 | 2,138 | 42,918 |
| **2013** | | | | |
| Generation | 41,616 | 19,517 | 2,716 | 24,815 |
| Distribution | 8,394 | 1,748 | 596 | 7,242 |
| Administration and Service | 10,545 | 1,991 | 161 | 8,715 |
| | 60,555 | 23,256 | 3,473 | 40,772 |

Financing charges capitalized on property, plant and equipment under construction were $146 thousand in 2014 (2013 – $376 thousand).

## 9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Regulatory assets:** | | |
| Environmental | 12,369 | 13,426 |
| RRPR variance account | 4,578 | 1,985 |
| Post-retirement and post-employment benefits | 2,637 | 2,939 |
| Total regulatory assets | 19,584 | 18,350 |
| Less: current portion | 1,301 | 2,427 |
| | 18,283 | 15,923 |
| **Regulatory liabilities:** | | |
| Deferred income tax regulatory liability | 4,333 | 4,347 |
| Total regulatory liabilities | 4,333 | 4,347 |
| Less: current portion | 120 | 109 |
| | 4,213 | 4,238 |

### Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. Management considers it probable that such expenditures will be recovered in the future through the rate-setting process, and as such, the Company has recorded an equivalent amount as a regulatory asset. In 2014, this regulatory asset increased by $180 thousand (2013 – $2,872 thousand) to reflect related changes in the Company's environmental liabilities. 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 Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2014 operation, maintenance and administration expenses would have been higher by $180 thousand (2013 – $2,872 thousand). In addition, 2014 amortization expense would have been lower by $1,598 thousand (2013 – $1,656 thousand), and 2014 financing charges would have been higher by $361 thousand (2013 – $330 thousand).

**RRPR Variance Account**

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2014, the Company has recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of net RRRP amounts received. At December 31, 2013, net RRRP amounts received were also lower than amounts required to achieve breakeven net income, and as such, a regulatory asset was also recognized. In the absence of rate-regulated accounting, 2014 revenue would have been lower by $2,593 thousand (2013 – $1,198 thousand).

**Post-Retirement and Post-Employment Benefits**

The Company 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 $302 thousand (2013 – $205 thousand).

**Deferred Income Tax Regulatory 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 recovery of PILs would have been lower by approximately $2 thousand (2013 – $367 thousand).

## 10. LONG-TERM DEBT

Long-term debt totalling $33,000 thousand is payable to Hydro One and consists of a $23,000 thousand note maturing in 2036 and a $10,000 thousand note maturing in 2044.

The $23,000 thousand note was issued on May 19, 2005, with an interest rate of 5.38% per annum and a maturity date of May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999 in consideration of the purchase price of Hydro One Remote Communities' net assets. On issuance of this note, $115 thousand of transaction costs and a $31 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

The $10,000 thousand note was issued on June 6, 2014, with an interest rate of 4.19% per annum and a maturity date of June 6, 2044. On issuance of this note, $50 thousand of transaction costs and a $10 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

## 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.

Hydro One Remote Communities 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 Remote Communities 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 Company's 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 Hierarchy**

The fair value hierarchy of financial assets and liabilities at December 31, 2014 and 2013 are as follows:

| *December 31, 2014 (thousands of Canadian dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 6,806 | 6,806 | 6,806 | – | – |
| Long-term debt | 33,000 | 39,226 | – | 39,226 | – |
| | 39,806 | 46,032 | 6,806 | 39,226 | – |

| *December 31, 2013 (thousands of Canadian dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 18,031 | 18,031 | 18,031 | – | – |
| Long-term debt | 23,000 | 25,450 | – | 25,450 | – |
| | 41,031 | 43,481 | 18,031 | 25,450 | – |

The fair value 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 foreign exchange risk is currently not significant, although Hydro One could in the future decide to issue and allocate foreign currency-denominated debt to the Company, along with an allocation of the resulting foreign exchange gains and losses. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%.

### *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 Remote Communities 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 Company's total provision for bad debts was $304 thousand (2013 – $296 thousand). 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 36% of the Company's current accounts receivable were aged more than 60 days (2013 – 47%). Sufficient allowances have been recorded to reflect the risk of potential credit losses.

### *Liquidity Risk*

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities 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 $9,812 thousand (2013 – $5,657 thousand) are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2014, Hydro One Remote Communities had long-term debt in the principal amount of $33,000 thousand (2013 – $23,000 thousand). No long-term debt matures during the next year. Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $1,656 thousand (2013 – $1,237 thousand). Principal repayments and interest payments are summarized by the number of years to maturity in the following table.

| **Years to Maturity** | **Principal Repayments on Long-term Debt** *(thousands of Canadian dollars)* | **Interest Payments** *(thousands of Canadian dollars)* | **Weighted Average Interest Rate** *(%)* |
|---|---|---|---|
| 1 year | – | 1,656 | 5.019 |
| 2 years | – | 1,656 | 5.019 |
| 3 years | – | 1,656 | 5.019 |
| 4 years | – | 1,656 | 5.019 |
| 5 years | – | 1,656 | 5.019 |
| | – | 8,280 | 5.019 |
| 6 – 10 years | – | 8,280 | 5.019 |
| Over 10 years | 33,000 | 22,405 | 5.019 |
| | 33,000 | 38,965 | 5.019 |

## 12. 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. 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 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.

Company and employees' 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, Hydro One Remote Communities charged $941 thousand (2013 – $775 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $272 thousand (2013 – $250 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2014 were $91 thousand (2013 – $264 thousand). In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $302 thousand (2013 – $205 thousand) was recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Accrued liabilities | 346 | 300 |
| Post-retirement and post-employment benefit liability | 12,862 | 12,088 |
| | 13,208 | 12,388 |

## 13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2014 and 2013:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Environmental liabilities, January 1 | 13,426 | 11,880 |
| Interest accretion | 361 | 330 |
| Expenditures | (1,598) | (1,656) |
| Revaluation adjustment | 180 | 2,872 |
| Environmental liabilities, December 31 | 12,369 | 13,426 |
| Less: current portion | 1,301 | 2,427 |
| | 11,068 | 10,999 |

The following table illustrates 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 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Undiscounted environmental liabilities, December 31 | 12,881 | 14,014 |
| Less: discounting accumulated liabilities to present value | 512 | 588 |
| Discounted environmental liabilities, December 31 | 12,369 | 13,426 |

At December 31, 2014, the estimated future environmental expenditures were as follows:

| *(thousands of Canadian dollars)* | |
|---|---|
| 2015 | 1,301 |
| 2016 | 2,619 |
| 2017 | 2,717 |
| 2018 | 1,851 |
| 2019 | 1,657 |
| Thereafter | 2,736 |
| | 12,881 |

The Company records a liability for the estimated future expenditures for the contaminated LAR 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 3.6% to 4.9%, 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.

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $12,881 thousand. These expenditures are expected to be incurred over the period from 2015 to 2020. 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 $180 thousand (2013 – $2,872 thousand).

## 14. SHARE CAPITAL

### Common Shares

The Company has 2 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

### Dividends

The Company has no retained earnings and does not pay dividends under its breakeven business model.

## 15. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities 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 Hydro One Remote Communities because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One Remote Communities are described below.

Hydro One Remote Communities receives amounts for RRRP from the IESO. RRRP amounts received for the year ended December 31, 2014 were $32,259 thousand (2013 – $33,046 thousand). Consistent with its breakeven business model, the Company recognized $34,852 thousand as RRRP revenue in 2014 (2013 – $34,245 thousand). This 2014 revenue exceeded amounts received by $2,593 thousand (2013 – $1,199 thousand) and the RRPR variance account balance was adjusted by this amount.

PILs are paid to or received from the OEFC.

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

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Accounts receivable | 106 | 97 |
| Income tax receivable | 2,683 | 2,697 |

Transactions with 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.

### Hydro One and Subsidiaries

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its other 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 corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2014 revenues include $109 thousand (2013 – $195 thousand) related to the provision of services to Hydro One and its other subsidiaries. 2014 operation, maintenance and administration costs include $2,958 thousand (2013 – $3,475 thousand) related to the purchase of services from Hydro One and its other subsidiaries.

The Company's long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One and its other subsidiaries. Financing charges include interest expense on the long-term debt in the amount of $1,477 thousand (2013 – $1,237 thousand), and interest expense on the inter-company demand facility in the amount of $187 thousand (2013 – $216 thousand). At December 31, 2014, the Company had accrued interest payable to Hydro One totaling $172 thousand (2013 – $142 thousand).

## 16. STATEMENTS OF CASH FLOWS

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

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Accounts receivable | 541 | (802) |
| Materials and supplies | (356) | 443 |
| Income taxes receivable | 14 | (1,108) |
| Long-term accounts receivable | (576) | (256) |
| Accounts payable | 173 | (284) |
| Accrued liabilities | 5,105 | (1,526) |
| Accrued interest | 30 | – |
| Post-retirement and post-employment benefit liability | 1,076 | 760 |
| | 6,007 | (2,773) |

| **Supplementary information:** | | |
|---|---|---|
| Net interest paid | 1,447 | 1,453 |

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any PILs paid are fully recovered.

## 17. CONTINGENCIES

### Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

### Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One 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, Hydro One paid approximately $1 million (2013 – $2 million) in respect of these consents. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One 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 Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

## 18. COMMITMENTS

### Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years.

During the year ended December 31, 2014, the Company made lease payments totalling $120 thousand (2013 – $1 million). At December 31, 2014, the future minimum lease payments under non-cancellable operating leases were as follows: 2015 – $120 thousand; 2016 – $120 thousand; 2017 – $120 thousand; 2018 – $150 thousand; 2019 – $150 thousand; and thereafter – $450 thousand.

# HYDRO ONE REMOTE COMMUNITIES INC.

# FINANCIAL STATEMENTS

## DECEMBER 31, 2015

**HYDRO ONE REMOTE COMMUNITIES INC.**
**INDEPENDENT AUDITORS' REPORT**

To Directors of Hydro One Remote Communities Inc.

We have audited the accompanying financial statements of Hydro One Remote Communities Inc., which comprise the balance sheet as at December 31, 2015, the statements of operations and comprehensive income, changes in shareholder's deficit and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these 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 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 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 Hydro One Remote Communities Inc. as at December 31, 2015 and its results of operations and its cash flows for the year then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 22, 2016

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)**
**For the years ended December 31, 2015 and 2014**

| **Year ended December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| **Revenues** *(Note 16)* | 48,321 | 52,130 |
| **Costs** | | |
| Operation, maintenance and administration *(Note 16)* | 17,863 | 20,069 |
| Fuel used for electric generation | 23,250 | 25,869 |
| Depreciation and amortization *(Note 4)* | 4,902 | 4,623 |
| | 46,015 | 50,561 |
| **Income before financing charges and income taxes** | **2,306** | **1,569** |
| Financing charges *(Notes 5, 16)* | 1,678 | 1,559 |
| **Income before income taxes** | **628** | **10** |
| Income taxes *(Notes 6, 16)* | 5,541 | 10 |
| **Net income (loss)** *(Note 6)* | **(4,913)** | **–** |
| Other comprehensive income | 14 | 13 |
| **Comprehensive income (loss)** | **(4,899)** | **13** |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS**
**At December 31, 2015 and 2014**

| **December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Accounts receivable (net of allowance for doubtful accounts – $156; 2014 – $145) *(Notes 7, 16)* | 4,435 | 4,454 |
| Regulatory assets *(Note 9)* | 1,483 | 1,301 |
| Fuel, materials and supplies | 2,740 | 2,092 |
| Deferred income tax assets *(Note 6)* | 125 | 120 |
| Income taxes receivable *(Notes 6, 16)* | 327 | 2,683 |
| | 9,110 | 10,650 |
| Property, plant and equipment *(Note 8)*: | | |
| Property, plant and equipment in service | 65,373 | 63,601 |
| Less: accumulated depreciation | 25,793 | 24,588 |
| | 39,580 | 39,013 |
| Construction in progress | 1,188 | 2,138 |
| Future use components and spares | 1,902 | 1,767 |
| | 42,670 | 42,918 |
| Other long-term assets: | | |
| Regulatory assets *(Note 9)* | 14,712 | 18,283 |
| Deferred income tax assets *(Note 6)* | 3,805 | 4,213 |
| Deferred debt issuance costs *(Note 10)* | 179 | 183 |
| Long-term accounts receivable (net of allowance for doubtful accounts – $111; 2014 – $159) *(Note 7)* | 1,070 | 1,250 |
| | 19,766 | 23,929 |
| **Total assets** | **71,546** | **77,497** |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS (continued)**
**At December 31, 2015 and 2014**

| **December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| **Liabilities** | | |
| Current liabilities: | | |
| Inter-company demand facility *(Notes 11, 16)* | 6,056 | 6,806 |
| Accounts payable | 1,344 | 876 |
| Accrued liabilities *(Notes 12)* | 4,377 | 8,936 |
| Accrued interest *(Note 16)* | 172 | 172 |
| Regulatory liabilities *(Note 9)* | 125 | 120 |
| Income taxes payable *(Note 6)* | 37 | – |
| | 12,111 | 16,910 |
| Long-term debt *(Notes 10, 11, 16)* | 33,000 | 33,000 |
| Other long-term liabilities: | | |
| Post-retirement and post-employment benefit liability *(Note 12)* | 13,517 | 12,862 |
| Regulatory liabilities *(Note 9)* | 3,805 | 4,213 |
| Environmental liabilities *(Note 13)* | 9,568 | 11,068 |
| | 26,890 | 28,143 |
| **Total liabilities** | **72,001** | **78,053** |
| *Contingencies and Commitments (Notes 18, 19)* | | |
| *Subsequent Event (Note 20)* | | |
| **Shareholder's deficit** | | |
| Common shares *(Note 14)* | 5,000 | – |
| Deficit | (4,913) | – |
| Accumulated other comprehensive loss | (542) | (556) |
| **Total shareholder's deficit** | **(455)** | **(556)** |
| **Total liabilities and shareholder's deficit** | **71,546** | **77,497** |

*See accompanying notes to Financial Statements.*

On behalf of the Board of Directors:

T. Kydd

Tom Kydd
Director

L. Cam

Lee Anne Cameron
Director

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CHANGES IN SHAREHOLDER'S DEFICIT**
**For the years ended December 31, 2015 and 2014**

| **Year ended December 31, 2015** *(thousands of Canadian dollars)* | **Common Shares** | **Deficit** | **Accumulated Other Comprehensive Loss** | **Total Shareholder's Deficit** |
|---|---|---|---|---|
| January 1, 2015 | – | – | (556) | (556) |
| Net income (loss) | – | (4,913) | – | (4,913) |
| Other comprehensive income | – | – | 14 | 14 |
| Common shares issued *(Note 14)* | 5,000 | – | – | 5,000 |
| **December 31, 2015** | 5,000 | (4,913) | (542) | (455) |

| **Year ended December 31, 2014** *(thousands of Canadian dollars)* | **Common Shares** | **Deficit** | **Accumulated Other Comprehensive Loss** | **Total Shareholder's Deficit** |
|---|---|---|---|---|
| January 1, 2014 | – | – | (569) | (569) |
| Other comprehensive loss | – | – | 13 | 13 |
| **December 31, 2014** | – | – | (556) | (556) |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CASH FLOWS**
**For the years ended December 31, 2015 and 2014**

| **Year ended December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| **Operating activities** | | |
| Net income (loss) | (4,913) | – |
| Environmental expenditures | (1,222) | (1,598) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (excluding removal costs) | 3,934 | 4,193 |
| Regulatory assets and liabilities | 1,819 | (2,594) |
| Amortization of hedging losses | 14 | 13 |
| Amortization of deferred debt issuance costs | 3 | 3 |
| Changes in non-cash balances related to operations *(Note 17)* | (1,422) | 6,007 |
| **Net cash from (used in) operating activities** | (1,787) | 6,024 |
| **Financing activities** | | |
| Common shares issued | 5,000 | – |
| Long-term debt issued | – | 10,000 |
| Other | – | (60) |
| **Net cash from financing activities** | 5,000 | 9,940 |
| **Investing activities** | | |
| Capital expenditures | (2,328) | (4,634) |
| Proceeds on disposition of property, plant and equipment | – | 12 |
| Future use assets | (135) | (117) |
| **Net cash used in investing activities** | (2,463) | (4,739) |
| **Net change in inter-company demand facility** | 750 | 11,225 |
| Inter-company demand facility, beginning of year | (6,806) | (18,031) |
| **Inter-company demand facility, end of year** | **(6,056)** | **(6,806)** |

*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 was wholly owned by the Province of Ontario (the Province) until October 31, 2015. On October 31, 2015, Hydro One Limited, a wholly owned subsidiary of the Province, acquired all issued and outstanding shares of Hydro One from the Province. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. The Company uses a cost recovery model applied to achieve breakeven net income and the Financial Statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2015 have been prepared and are publicly available.

For the year ended December 31, 2015, the Company has reported a net loss due to recognition of tax expense resulting from the Company no longer being exempt from tax under the Federal Tax Regime. This tax is not recovered from ratepayers as it is funded by the Company's shareholder, and therefore, it is not included in the cost recovery model applied to achieve breakeven net income. See Note 6 – Income Taxes.

Hydro One Remote Communities performed an evaluation of subsequent events through to April 22, 2016, 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 20 – Subsequent Event.

### Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairment, contingencies, unbilled revenue, allowance for doubtful accounts 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.

### Rate Setting

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

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

**Revenue Recognition**

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

Revenues are recorded net of indirect taxes.

**Accounts Receivable and Allowance for Doubtful Accounts**

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are 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.

Long-term accounts receivable are recorded at their invoiced amount and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. Provision for uncollectible amounts for this component is set at the inception of the balance and is maintained until settlement of those amounts. The provision for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

**Income Taxes**

On October 31, 2015, the Company ceased to be exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (Federal Tax Regime). Prior to that date, Hydro One Remote Communities was required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the *Electricity Act*, 1998

(Ontario) (PILs Regime). These payments were 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. Upon exiting the PILs Regime, Hydro One Remote Communities 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 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 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 Statements of Operations and Comprehensive Income (Loss).

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.

### Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash 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%.

### Fuel, Materials and Supplies

Fuel is used in the generation of electricity. 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 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

***Generation***

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

***Distribution***

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

***Administration and Service***

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

**Capitalized Financing Costs**

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 (Loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

**Construction in Progress**

Construction 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**

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 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 |
|---|---|---|---|
| Generation | 20 years | 3% – 7% | 5% |
| Distribution | 45 years | 1% – 7% | 2% |
| Administration and service | 36 years | 3% – 20% | 4% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 assets where no asset retirement obligation 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 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.

The carrying costs of most of Hydro One Remote Communities' 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. As at December 31, 2015 and 2014, no asset impairment had been recorded.

### 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 Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income (Loss). 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents OCI and net income in a single continuous Statement of Operations and Comprehensive Income (Loss).

### 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.

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 11 – Fair Value of Financial Instruments and Risk Management.

### Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2015 and 2014. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

### Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's 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 plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets 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, 2015, the measurement date for all plans was December 31.

***Pension benefits***

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit 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, 2015.

***Post-retirement and post-employment benefits***

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of the these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's 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 accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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.

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, 2015.

**Stock-Based Compensation**

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited 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.

**Loss Contingencies**

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

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

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement 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 Remote Communities records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

## 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 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 2015-05, 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 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 financial statements.

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 Balance Sheets.

## 4. DEPRECIATION AND AMORTIZATION

| **Year ended December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Depreciation of property, plant and equipment | 2,711 | 2,594 |
| Asset removal costs | 968 | 430 |
| Amortization of regulatory assets | 1,223 | 1,599 |
| | 4,902 | 4,623 |

## 5. FINANCING CHARGES

| **Year ended December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Interest on long-term debt | 1,655 | 1,477 |
| Interest on inter-company demand facility | 65 | 187 |
| Amortization of hedging losses | 14 | 13 |
| Other | 41 | 28 |
| Less: Interest capitalized on construction in progress | (97) | (146) |
| | 1,678 | 1,559 |

## 6. 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** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Income taxes / provision for PILs at statutory rate | 166 | 3 |
| Increase (decrease) resulting from: | | |
| Net temporary differences included in amounts charged to customers: | | |
| Depreciation and amortization in excess of capital cost allowance | 1,112 | 338 |
| RRPR variance account | 482 | (687) |
| Post-retirement and post-employment benefit expense in excess of cash payments | 201 | 189 |
| Losses carryforward | (870) | 846 |
| Environmental expenditures | (324) | (424) |
| Overheads capitalized for accounting but deducted for tax purposes | (141) | (93) |
| Pension contribution in excess of pension expense | (119) | (132) |
| Interest capitalized for accounting but deducted for tax purposes | (26) | (39) |
| Other | 72 | – |
| Net temporary differences | 387 | (2) |
| Net tax expense resulting from transition from PILs Regime to Federal Tax Regime | 5,000 | – |
| Prior year adjustments | (3) | 10 |
| Other permanent differences | (9) | (1) |
| Total income taxes / provision for PILs | 5,541 | 10 |
| | | |
| Current income taxes / provision for PILs | 5,541 | 10 |
| Deferred income taxes / provision for PILs | – | – |
| Total income taxes / provision for PILs | 5,541 | 10 |
| | | |
| Effective income tax rate | 882% | 100% |

The provision for PILs / current income taxes is remitted to, or received from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime), respectively. At December 31, 2015, the Company had $327 thousand (2014 – $2,683 thousand) receivable from the OEFC, and $37 thousand (2014 – $nil) payable to the CRA.

### Departure Tax

On October 31, 2015, the Company's exemption from tax under the Federal Tax Regime ceased to apply. Under the PILs Regime, the Company 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 Remote Communities making payments in lieu of tax (Departure Tax) totaling $5,000 thousand. To enable Hydro One Remote Communities to make the Departure Tax payment, Hydro One subscribed for 64 common shares of Hydro One Remote Communities for $5,000 thousand. The Company used the proceeds of this share subscription to pay the Departure Tax.

For the year ended December 31, 2015, Hydro One Remote Communities' income taxes include tax expense relating to payment of Departure Tax of $5,000 thousand (2014 – $nil) and income tax recovery of $87 thousand (2014 – $nil) relating to the partial utilization of the deferred tax asset generated upon the transition from the PILs Regime to the Federal Tax Regime.

The following table presents a reconciliation of net income (loss) to net income under the cost recovery model to achieve breakeven net income:

| **Year ended December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Net income before income taxes | 628 | 10 |
| Income taxes under cost-recovery model | 628 | 10 |
| Net income under cost-recovery model | – | – |
| Tax expense – Departure Tax | 5,000 | – |
| Tax recovery | (87) | – |
| Net income (loss) | (4,913) | – |

### Deferred Income Tax Assets

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, 2015 and 2014, deferred income tax assets and liabilities consisted of the following:

| **Year ended December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| **Deferred income tax assets** | | |
| Post-retirement and post-employment benefits expense in excess of cash payments | 5,038 | 4,762 |
| Environmental expenditures | 3,984 | 4,459 |
| Depreciation and amortization in excess of capital cost allowance | 926 | 1,231 |
| Non capital losses | – | 1,183 |
| Regulatory amounts not recognized for tax | (5,803) | (7,060) |
| Other | (215) | (242) |
| Total deferred income tax assets | 3,930 | 4,333 |
| Less: current portion | 125 | 120 |
| | 3,805 | 4,213 |

During 2015 and 2014, there was no change in the rate applicable to future taxes. The Company has recorded a valuation allowance in the amount of $6,622 thousand (2014 – $nil) in respect of capital property.

## 7. ACCOUNTS RECEIVABLE

| **December 31, 2015** *(thousands of Canadian dollars)* | **Current accounts receivable** | **Long-term accounts receivable** | **Total** |
|---|---|---|---|
| Accounts receivable – billed | 3,514 | 1,181 | 4,695 |
| Accounts receivable – unbilled | 1,077 | – | 1,077 |
| Accounts receivable, gross | 4,591 | 1,181 | 5,772 |
| Allowance for doubtful accounts | (156) | (111) | (267) |
| Accounts receivable, net | 4,435 | 1,070 | 5,505 |

| **December 31, 2014** *(thousands of Canadian dollars)* | **Current accounts receivable** | **Long-term accounts receivable** | **Total** |
|---|---|---|---|
| Accounts receivable – billed | 3,214 | 1,409 | 4,623 |
| Accounts receivable – unbilled | 1,385 | – | 1,385 |
| Accounts receivable, gross | 4,599 | 1,409 | 6,008 |
| Allowance for doubtful accounts | (145) | (159) | (304) |
| Accounts receivable, net | 4,454 | 1,250 | 5,704 |

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2015 and 2014:

| **December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Allowance for doubtful accounts – January 1 | (304) | (296) |
| Write-offs | 67 | 77 |
| Adjustments to allowance for doubtful accounts | (30) | (85) |
| Allowance for doubtful accounts – December 31 | (267) | (304) |

## 8. PROPERTY, PLANT AND EQUIPMENT

| **December 31, 2015** *(thousands of Canadian dollars)* | **Property, Plant and Equipment** | **Accumulated Depreciation** | **Construction in Progress** | **Total** |
|---|---|---|---|---|
| Generation | 45,779 | 21,150 | 826 | 25,455 |
| Distribution | 9,780 | 2,049 | 312 | 8,043 |
| Administration and Service | 11,716 | 2,594 | 50 | 9,172 |
| | 67,275 | 25,793 | 1,188 | 42,670 |

| **December 31, 2014** *(thousands of Canadian dollars)* | **Property, Plant and Equipment** | **Accumulated Depreciation** | **Construction in Progress** | **Total** |
|---|---|---|---|---|
| Generation | 44,770 | 20,385 | 1,742 | 26,127 |
| Distribution | 9,488 | 1,906 | 99 | 7,681 |
| Administration and Service | 11,110 | 2,297 | 297 | 9,110 |
| | 65,368 | 24,588 | 2,138 | 42,918 |

Financing charges capitalized on property, plant and equipment under construction were $97 thousand in 2015 (2014 – $146 thousand).

## 9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

| **December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| **Regulatory assets:** | | |
| Environmental | 11,051 | 12,369 |
| RRPR variance account | 2,760 | 4,578 |
| Post-retirement and post-employment benefits | 2,285 | 2,637 |
| Share-based compensation | 99 | – |
| Total regulatory assets | 16,195 | 19,584 |
| Less: current portion | 1,483 | 1,301 |
| | 14,712 | 18,283 |
| | | |
| **Regulatory liabilities:** | | |
| Deferred income tax regulatory liability | 3,930 | 4,333 |
| Total regulatory liabilities | 3,930 | 4,333 |
| Less: current portion | 125 | 120 |
| | 3,805 | 4,213 |

### Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recovered in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2015, the environmental regulatory asset decreased by $448 thousand (2014 – increased by $180 thousand) to reflect related changes in the Company's environmental liabilities. 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 Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2015 operation, maintenance and administration expenses would have been lower by $448 thousand (2014 – higher by $180 thousand). In addition, 2015 amortization expense would have been lower by $1,222 thousand (2014 – $1,598 thousand), and 2015 financing charges would have been higher by $352 thousand (2014 – $361 thousand).

**RRPR Variance Account**

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2015, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of cumulative RRRP amounts received. In 2015, RRRP amounts received were higher than amounts required to achieve breakeven net income, and as such, the regulatory asset was reduced by $1,818 thousand. In the absence of rate-regulated accounting, 2015 revenue would have been higher by $1,818 thousand (2014 – lower by $2,593 thousand).

**Post-Retirement and Post-Employment Benefits**

The Company 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, 2015 OCI would have been higher by $352 thousand (2014 – $302 thousand).

**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 Hydro One Limited 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 $69 thousand (2014 – $nil).

**Deferred Income Tax Regulatory 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 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 lower by approximately $387 thousand (2014 – higher by $2 thousand).

## 10. LONG-TERM DEBT

Long-term debt totalling $33,000 thousand is payable to Hydro One and consists of a $23,000 thousand note maturing in 2036 and a $10,000 thousand note maturing in 2044.

The $23,000 thousand note was issued on May 19, 2005, with an interest rate of 5.38% per annum and a maturity date of May 20, 2036. On issuance of this note, $115 thousand of transaction costs and a $31 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

The $10,000 thousand note was issued on June 6, 2014, with an interest rate of 4.19% per annum and a maturity date of June 6, 2044. On issuance of this note, $50 thousand of transaction costs and a $10 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

## 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.

Hydro One Remote Communities 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 Remote Communities 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, 2015 and 2014, the Company's 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 Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2015 and 2014 are as follows:

| **December 31, 2015** *(thousands of Canadian dollars)* | **Carrying Value** | **Fair Value** | **Level 1** | **Level 2** | **Level 3** |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 6,056 | 6,056 | 6,056 | – | – |
| Long-term debt | 33,000 | 37,957 | – | 37,957 | – |
| | 39,056 | 44,013 | 6,056 | 37,957 | – |

| **December 31, 2014** *(thousands of Canadian dollars)* | **Carrying Value** | **Fair Value** | **Level 1** | **Level 2** | **Level 3** |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 6,806 | 6,806 | 6,806 | – | – |
| Long-term debt | 33,000 | 39,226 | – | 39,226 | – |
| | 39,806 | 46,032 | 6,806 | 39,226 | – |

The fair value 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, 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 commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The foreign exchange risk is currently not significant, although Hydro One could in the future decide to issue and allocate foreign currency-denominated debt to the Company, along with an allocation of the resulting foreign exchange gains and losses. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%.

***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 Remote Communities did not earn a significant amount of revenue from any individual 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 total provision for bad debts was $267 thousand (2014 – $304 thousand). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2015, approximately 44% (2014 – 36%) of the Company's current accounts receivable were aged more than 60 days. Sufficient allowances have been recorded to reflect the risk of potential credit losses.

***Liquidity Risk***

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities 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, 2015, accounts payable and accrued liabilities in the amount of $5,721 thousand (2014 – $9,812 thousand) are expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2015, Hydro One Remote Communities had long-term debt in the principal amount of $33,000 thousand (2014 – $33,000 thousand). Principal repayments and 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** *(thousands of Canadian dollars)* | **Weighted Average Interest Rate** *(%)* |
|---|---|---|
| 1 year | – | 5.0 |
| 2 years | – | 5.0 |
| 3 years | – | 5.0 |
| 4 years | – | 5.0 |
| 5 years | – | 5.0 |
| | – | 5.0 |
| 6 – 10 years | – | 5.0 |
| Over 10 years | 33,000 | 5.0 |
| | 33,000 | 5.0 |

Interest payments on long-term debt are summarized by year in the following table:

| **Year** | **Interest Payments** *(thousands of Canadian dollars)* |
|---|---|
| 2016 | 1,656 |
| 2017 | 1,656 |
| 2018 | 1,656 |
| 2019 | 1,656 |
| 2020 | 1,656 |
| | 8,280 |
| 2021-2025 | 8,282 |
| 2026 + | 20,744 |
| | 37,306 |

## 12. 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 most regular employees of Hydro One and its subsidiaries. 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 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.

Company 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 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.

At December 31, 2015, based on the December 31, 2013 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,683 million (2014 – $7,535 million). The fair value of pension plan assets available for these benefits was $6,731 million (2014 – $6,299 million).

### Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2015, Hydro One Remote Communities charged $759 thousand (2014 – $941 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $326 thousand (2014 – $272 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2015 were $51 thousand (2014 – $91 thousand). In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $352 thousand (2014 – $302 thousand) was recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

| **December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Accrued liabilities | 373 | 346 |
| Post-retirement and post-employment benefit liability | 13,517 | 12,862 |
| | 13,890 | 13,208 |

## 13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2015 and 2014:

| **Year ended December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Environmental liabilities, January 1 | 12,369 | 13,426 |
| Interest accretion | 352 | 361 |
| Expenditures | (1,222) | (1,598) |
| Revaluation adjustment | (448) | 180 |
| Environmental liabilities, December 31 | 11,051 | 12,369 |
| Less: current portion | 1,483 | 1,301 |
| | 9,568 | 11,068 |

The following table shows 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** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Undiscounted environmental liabilities | 11,474 | 12,881 |
| Less: discounting accumulated liabilities to present value | 423 | 512 |
| Discounted environmental liabilities | 11,051 | 12,369 |

At December 31, 2015, the estimated future environmental expenditures were as follows:

| *(thousands of Canadian dollars)* | |
|---|---|
| 2016 | 1,483 |
| 2017 | 1,960 |
| 2018 | 1,891 |
| 2019 | 2,429 |
| 2020 | 3,711 |
| | 11,474 |

The Company records a liability for the estimated future expenditures for the contaminated LAR 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 a rate of 3.6%. 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.

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $11,474 thousand. These expenditures are expected to be incurred over the period from 2016 to 2020. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2015 to decrease the LAR environmental liability by $448 thousand (2014 – increase of $180 thousand).

## 14. SHARE CAPITAL

### Common Shares

The Company has 267 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

The following table presents the movement in common shares during the year ended December 31, 2015. There was no movement in common shares during the year ended December 31, 2014.

| *(number of common shares)* | |
|---|---|
| Number of common shares – January 1, 2015 | 2 |
| Share split *(a)* | 200 |
| Common shares issued *(b)* | 64 |
| Common shares issued *(c)* | 1 |
| Number of common shares – December 31, 2015 | 267 |

(a) On November 2, 2015, all of the issued and outstanding common shares of Hydro Once Remote Communities were changed into 202 issued and outstanding common shares of the Company.

(b) On November 4, 2015, Hydro One Remote Communities issued 64 common shares to Hydro One for proceeds of $5 million.

(c) On November 3, 2015, Hydro One Remote Communities declared a stock dividend on its common shares, which due to the number of shares issued and the resulting effect on the price per share was treated as a stock split. On November 5, 2015, Hydro One Remote Communities effected a reverse split and issued as consideration one common share to Hydro One. There was no impact to the capital structure of Hydro One Remote Communities as a net result of the stock dividend and the reverse split.

### Dividends

The Company does not pay dividends under its breakeven business model.

## 15. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Remote communities, in current and future periods.

### Share Grant Plans

At December 31, 2015, Hydro One Limited 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). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees of Hydro One Remote Communities.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The fair value of the Hydro One Limited share grants is estimated based on the grant date Hydro One Limited 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 to employees of Hydro One Remote Communities in 2015 is $1,091 thousand (2014 – $nil). Total share based compensation recognized during 2015 by Hydro One Remote Communities was $99 thousand (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 Hydro One Remote Communities' share grant activity under the Share Grant Plans as of December 31, 2015 is presented below:

| Year ended December 31, 2015 | Share Grants *(Number)* | Weighted-Average Price |
|---|---|---|
| **Outstanding – beginning of year** | – | – |
| Granted (non-vested) | 53,196 | $20.50 |
| **Outstanding – end of year** | 53,196 | – |

### Employee Share Ownership Plan

Effective December 15, 2015, Hydro One Limited 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 Limited. 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 Limited adopted a Long-term Incentive Plan (LTIP). Under the LTIP, long-term incentives will be granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited 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 of Hydro One Limited.

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.

## 16. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited, and the Province is the majority shareholder of Hydro One Limited. The OEFC and IESO are related parties to Hydro One Remote Communities because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One Remote Communities are described below.

### IESO

- Hydro One Remote Communities receives amounts for RRRP from the IESO. RRRP amounts received for the year ended December 31, 2015 were $32,259 thousand (2014 – $32,259 thousand). Consistent with its breakeven business model, the Company recognized $30,441 thousand as RRRP revenue in 2015 (2014 – $34,852 thousand), with the difference recorded in the RRPR variance account.

### OEFC

- In 2015, Hydro One Remote Communities made a Departure Tax payment to the OEFC totaling $5 million (2014 – $nil).

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

| **December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Accounts receivable | 95 | 106 |
| Income tax receivable | 327 | 2,683 |

Transactions with 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.

### Hydro One and Subsidiaries

- The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its other 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 corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. Revenues in 2015 include $213 thousand (2014 – $109 thousand) related to the provision of services to Hydro One and its other subsidiaries. Operation, maintenance and administration costs in 2015 include $2,973 thousand (2014 – $2,958 thousand) related to the purchase of services from Hydro One and its other subsidiaries.
- The Company's long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One and its other subsidiaries. Financing charges include interest expense on the long-term debt in the amount of $1,655 thousand (2014 – $1,477 thousand), and interest expense on the inter-company demand facility in the amount of $65 thousand (2014 – $187 thousand). At December 31, 2015, the Company had accrued interest payable to Hydro One totaling $172 thousand (2014 – $172 thousand).
- On November 4, 2015, Hydro One Remote Communities issued 64 common shares to Hydro One for proceeds of $5 million.
- In 2015, Hydro One Limited established certain stock-based compensation plans, however they represent components of costs of Hydro One and its subsidiaries, including Hydro One Remote Communities in current and future periods. Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with the share grant plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans. At December 31, 2015, Hydro One Remote Communities had a payable of $99 thousand (2014 – $nil) to Hydro One associated with these plans. See Note 15 – Stock-based Compensation.

## 17. STATEMENTS OF CASH FLOWS

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

| **Year ended December 31** *(thousands of Canadian dollars)* | **2015** | **2014** |
|---|---|---|
| Accounts receivable | 19 | 541 |
| Fuel, materials and supplies | (648) | (356) |
| Income taxes receivable | 2,356 | 14 |
| Long-term accounts receivable | 180 | (576) |
| Accounts payable | 468 | 173 |
| Accrued liabilities | (4,741) | 5,105 |
| Accrued interest | – | 30 |
| Income taxes payable | 37 | – |
| Post-retirement and post-employment benefit liability | 907 | 1,076 |
| | (1,422) | 6,007 |
| **Supplementary information:** | | |
| Net interest paid | 1,655 | 1,447 |
| Taxes paid | 5,000 | – |

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid are fully recovered.

## 18. CONTINGENCIES

### Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

In September 2015, Hydro One and three of its subsidiaries, including Hydro One Remote Communities, 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 Hydro One 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, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One 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, Hydro One paid approximately $1 million (2014 – $1 million) in respect of these consents. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One 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 Hydro One’s and the Company’s results of operations if Hydro One is not able to recover them in future rate orders.

## 19. COMMITMENTS

### Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years.

During the year ended December 31, 2015, the Company made lease payments totalling $120 thousand (2014 – $120 million). At December 31, 2015, the future minimum lease payments under non-cancellable operating leases were as follows: 2016 – $120 thousand; 2017 – $120 thousand; 2018 – $150 thousand; 2019 – $150 thousand; 2020 – $150 thousand; and thereafter – $300 thousand.

## 20. SUBSEQUENT EVENT

### Long-term Debt

On February 24, 2016, Hydro One Remote Communities issued a $10,000 thousand note with a maturity date of February 24, 2026 and a coupon rate of 2.79%. The note is payable to Hydro One Inc.

# HYDRO ONE REMOTE COMMUNITIES INC.

## FINANCIAL STATEMENTS

### DECEMBER 31, 2016

**HYDRO ONE REMOTE COMMUNITIES INC.**
**INDEPENDENT AUDITORS' REPORT**

To Directors of Hydro One Remote Communities Inc.

We have audited the accompanying financial statements of Hydro One Remote Communities Inc., which comprise the balance sheet as at December 31, 2016, the statements of operations and comprehensive income, changes in shareholder's equity (deficit) and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these 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 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 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 Hydro One Remote Communities Inc. as at December 31, 2016 and its results of operations and its cash flows for the year then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 27, 2017

## HYDRO ONE REMOTE COMMUNITIES INC.
## STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
### For the years ended December 31, 2016 and 2015

| Year ended December 31 *(thousands of Canadian dollars)* | 2016 | 2015 |
|---|---|---|
| **Revenues** *(Note 16)* | 50,357 | 48,321 |
| **Costs** | | |
| Operation, maintenance and administration | 19,826 | 17,863 |
| Fuel used for electric generation | 23,669 | 23,250 |
| Depreciation and amortization *(Note 4)* | 4,618 | 4,902 |
| | 48,113 | 46,015 |
| **Income before financing charges and income taxes** | **2,244** | **2,306** |
| Financing charges *(Notes 5, 16)* | 1,797 | 1,678 |
| **Income before income taxes** | **447** | **628** |
| Income tax expense (recovery) *(Notes 6, 16)* | (73) | 5,541 |
| **Net income (loss)** *(Note 6)* | **520** | **(4,913)** |
| Other comprehensive income | 14 | 14 |
| **Comprehensive income (loss)** | **534** | **(4,899)** |

*See accompanying notes to Financial Statements.*

## HYDRO ONE REMOTE COMMUNITIES INC.
## BALANCE SHEETS
### At December 31, 2016 and 2015

| December 31 *(thousands of Canadian dollars)* | 2016 | 2015 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Inter-company demand facility *(Note 16)* | 7,253 | – |
| Accounts receivable *(Notes 7, 16)* | 5,557 | 4,435 |
| Regulatory assets *(Note 9)* | 1,183 | 1,483 |
| Fuel, materials and supplies | 2,476 | 2,740 |
| Deferred income tax assets *(Note 6)* | – | 125 |
| Income taxes receivable *(Notes 6, 16)* | 463 | 327 |
| | 16,932 | 9,110 |
| Property, plant and equipment *(Note 8)* | 43,626 | 42,670 |
| Other long-term assets: | | |
| Regulatory assets *(Note 9)* | 38,958 | 14,712 |
| Deferred income tax assets *(Note 6)* | 4,218 | 3,805 |
| Long-term accounts receivable *(Note 7)* | 645 | 1,070 |
| Other assets | 24 | – |
| | 43,845 | 19,587 |
| **Total assets** | **104,403** | **71,367** |
| **Liabilities** | | |
| Current liabilities: | | |
| Inter-company demand facility *(Note 16)* | – | 6,056 |
| Accounts payable | 1,383 | 1,344 |
| Accrued liabilities | 6,309 | 4,377 |
| Accrued interest *(Note 16)* | 280 | 172 |
| Regulatory liabilities *(Note 9)* | – | 125 |
| Income taxes payable *(Note 6)* | – | 37 |
| | 7,972 | 12,111 |
| Long-term liabilities: | | |
| Long-term debt *(Notes 10, 11, 16)* | 42,783 | 32,821 |
| Post-retirement and post-employment benefit liability *(Note 12)* | 14,689 | 13,517 |
| Regulatory liabilities *(Note 9)* | 4,218 | 3,805 |
| Environmental liabilities *(Note 13)* | 34,662 | 9,568 |
| | 96,352 | 59,711 |
| **Total liabilities** | **104,324** | **71,822** |
| *Contingencies and Commitments (Notes 18, 19)* | | |
| **Shareholder's equity (deficit)** | | |
| Common shares *(Note 14)* | 5,000 | 5,000 |
| Deficit | (4,393) | (4,913) |
| Accumulated other comprehensive loss | (528) | (542) |
| **Total shareholder's equity (deficit)** | **79** | **(455)** |
| **Total liabilities and shareholder's equity (deficit)** | **104,403** | **71,367** |

*See accompanying notes to Financial Statements.*

On behalf of the Board of Directors:

Greg Kiraly
Director

Maureen Wareham
Director

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (DEFICIT)**
**For the years ended December 31, 2016 and 2015**

| Year ended December 31, 2016 *(thousands of Canadian dollars)* | Common Shares | Deficit | Accumulated Other Comprehensive Loss | Total Shareholder's Equity (Deficit) |
|---|---|---|---|---|
| January 1, 2016 | 5,000 | (4,913) | (542) | (455) |
| Net income | – | 520 | – | 520 |
| Other comprehensive income | – | – | 14 | 14 |
| **December 31, 2016** | 5,000 | (4,393) | (528) | 79 |

| Year ended December 31, 2015 *(thousands of Canadian dollars)* | Common Shares | Deficit | Accumulated Other Comprehensive Loss | Total Shareholder's Deficit |
|---|---|---|---|---|
| January 1, 2015 | – | – | (556) | (556) |
| Net loss | – | (4,913) | – | (4,913) |
| Other comprehensive income | – | – | 14 | 14 |
| Common shares issued *(Note 14)* | 5,000 | – | – | 5,000 |
| **December 31, 2015** | 5,000 | (4,913) | (542) | (455) |

*See accompanying notes to Financial Statements.*

## HYDRO ONE REMOTE COMMUNITIES INC.
## STATEMENTS OF CASH FLOWS
### For the years ended December 31, 2016 and 2015

| Year ended December 31 *(thousands of Canadian dollars)* | 2016 | 2015 |
|---|---|---|
| **Operating activities** | | |
| Net income (loss) | 520 | (4,913) |
| Environmental expenditures | (1,247) | (1,222) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (excluding removal costs) | 3,998 | 3,934 |
| Regulatory assets and liabilities | 897 | 1,819 |
| Other | 21 | 17 |
| Changes in non-cash balances related to operations *(Note 17)* | 2,871 | (1,422) |
| **Net cash from (used in) operating activities** | 7,060 | (1,787) |
| **Financing activities** | | |
| Common shares issued | – | 5,000 |
| Long-term debt issued | 10,000 | – |
| Other | (43) | – |
| **Net cash from financing activities** | 9,957 | 5,000 |
| **Investing activities** | | |
| Capital expenditures | (4,179) | (2,328) |
| Capital contributions received | 582 | – |
| Future use assets | (111) | (135) |
| **Net cash used in investing activities** | (3,708) | (2,463) |
| **Net change in inter-company demand facility** | 13,309 | 750 |
| Inter-company demand facility, beginning of year | (6,056) | (6,806) |
| **Inter-company demand facility, end of year** | **7,253** | **(6,056)** |

*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 was wholly owned by the Province of Ontario (the Province) until October 31, 2015. On October 31, 2015, Hydro One Limited, a wholly owned subsidiary of the Province, acquired all issued and outstanding shares of Hydro One from the Province. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. The Company uses a cost recovery model applied to achieve breakeven net income and the Financial Statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2016 have been prepared and are publicly available.

For the year ended December 31, 2015, the Company has reported a net loss due to recognition of tax expense resulting from the Company no longer being exempt from tax under the Federal Tax Regime. This tax is not recovered from ratepayers as it is funded by the Company's shareholder, and therefore, it is not included in the cost recovery model applied to achieve breakeven net income. See note 6 – Income Taxes.

Hydro One Remote Communities performed an evaluation of subsequent events through to April 27, 2017, 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. No such events or transactions were identified.

### Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

### Rate Setting

On March 17, 2016, the OEB approved an increase of 2.10% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2016.

### 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 include its regulatory assets and liabilities in 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 would be reflected in results of operations in the period that the assessment is made.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

The departure tax recovery is not recoverable from ratepayers and therefore is not included in the cost recovery model applied to achieve breakeven net income.

### Revenue Recognition

Revenues attributable to the generation and 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. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

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

Revenues are recorded net of indirect taxes.

### Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are 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 billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed 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 allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Long-term accounts receivable are recorded at their invoiced amount and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. Provision for uncollectible amounts for this component is set at the inception of the balance and is maintained until settlement of those amounts. The provision for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

### Income Taxes

On October 31, 2015, the Company ceased to be exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (Federal Tax Regime). Prior to that date, Hydro One Remote Communities was required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the *Electricity Act*, 1998 (Ontario) (PILs Regime). These payments were 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. Upon exiting the PILs Regime, Hydro One Remote Communities 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 Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

<u>Deferred Income Taxes</u>

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 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 Statements of Operations and Comprehensive Income (Loss).

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.

**Inter-company Demand Facility**

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash 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%.

**Fuel, Materials and Supplies**

Fuel is used in the generation of electricity. 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 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

Generation

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

Distribution

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

Administration and Service

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

**Capitalized Financing Costs**

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 Statements of Operations and Comprehensive Income (Loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

### Construction in Progress

Construction 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

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 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 |
|---|---|---|---|
| Generation | 20 years | 3% – 7% | 5% |
| Distribution | 46 years | 1% – 7% | 2% |
| Administration and service | 36 years | 3% – 20% | 4% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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.

### 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 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.

The carrying costs of most of Hydro One Remote Communities' 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. As at December 31, 2016 and 2015, no asset impairment had been recorded.

### 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 net of related debt on the Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income (Loss). 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents net income and OCI in a single continuous Statement of Operations and Comprehensive Income (Loss).

### 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 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.

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 11 – Fair Value of Financial Instruments and Risk Management.

### Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2016 and 2015. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

### Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's 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 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 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, 2016, the measurement date for all plans was December 31.

Pension Benefits

Hydro One has a contributory defined benefit pension plan (Pension Plan) covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the Pension Plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Statements of Operations and Comprehensive Income (Loss).

A detailed description of Hydro One pension plans is provided in note 18 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2016.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's 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 accumulated OCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the “corridor” approach. The amount calculated above the “corridor” is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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 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 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.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in note 18 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2016.

**Stock-Based Compensation**

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited’s 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. Forfeitures are recognized as they occur (see note 3).

Long-term Incentive Plan (LTIP)

The Company measures its LTIP at fair value based on the grant date share price of Hydro One Limited’s common shares. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

**Loss Contingencies**

Hydro One Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its 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 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 Remote Communities records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) 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 Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

### 3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One Remote Communities:

**Recently Adopted Accounting Guidance**

| ASU | Date issued | Description | Effective date | Impact on Hydro One |
|---|---|---|---|---|
| 2015-01 | January 2015 | Extraordinary items are no longer required to be presented separately in the income statement. | January 1, 2016 | No material impact upon adoption |
| 2015-03 | April 2015 | Debt issuance costs are required to be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums. | January 1, 2016 | Reclassification of deferred debt issuance costs and net unamortized debt premiums as an offset to long-term debt. Applied retrospectively (see note 10). |
| 2015-05 | April 2015 | Cloud computing arrangements that have been assessed to contain a software licence should be accounted for as internal-use software. | January 1, 2016 | No material impact upon adoption |
| 2015-17 | November 2015 | All deferred tax assets and liabilities are required to be classified as noncurrent on the balance sheet. | January 1, 2017 | This ASU was early adopted as of April 1, 2016 and was applied prospectively. As a result, the current portions of the Company's deferred income tax assets are reclassified as noncurrent assets on the Balance Sheet. Prior periods were not retrospectively adjusted (see note 6). |
| 2016-09 | March 2016 | Several aspects of the accounting for stock-based payment transactions were simplified, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. | January 1, 2017 | This ASU was early adopted as of October 1, 2016 and was applied retrospectively. As a result, the Company accounts for forfeitures as they occur. There were no other material impacts upon adoption. |

**Recently Issued Accounting Guidance Not Yet Adopted**

| ASU | Date issued | Description | Effective date | Anticipated impact on Hydro One |
|---|---|---|---|---|
| 2014-09<br>2015-14<br>2016-08<br>2016-10<br>2016-12<br>2016-20 | May 2014 – December 2016 | ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard. | January 1, 2018 | Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is now underway and will continue through to the third quarter of 2017, with the end result being a determination of the financial impact of this standard. The Company is on track for implementation of this standard by the effective date. |
| 2016-02 | February 2016 | Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. | January 1, 2019 | An initial assessment is currently underway encompassing a review of all existing leases, which will be followed by a detailed review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date. |
| 2016-13 | June 2016 | The amendment provides users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. | January 1, 2019 | Under assessment |
| 2016-15 | August 2016 | The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice. | January 1, 2018 | Under assessment |
| 2016-18 | November 2016 | The amendment requires that restricted cash or restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning and end-of-period balances in the statement of cash flows. | January 1, 2018 | Under assessment |

## 4. DEPRECIATION AND AMORTIZATION

| Year ended December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Depreciation of property, plant and equipment | 2,751 | 2,711 |
| Asset removal costs | 620 | 968 |
| Amortization of regulatory assets | 1,247 | 1,223 |
| | 4,618 | 4,902 |

## 5. FINANCING CHARGES

| Year ended December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Interest on long-term debt | 1,915 | 1,655 |
| Interest expense (income) on inter-company demand facility | (48) | 65 |
| Amortization of hedging losses | 14 | 14 |
| Other | 31 | 41 |
| Interest capitalized on construction in progress | (115) | (97) |
| | 1,797 | 1,678 |

## 6. 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 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Income taxes / provision for PILs at statutory rate | 118 | 166 |
| Increase (decrease) resulting from: | | |
| Net temporary differences recoverable in future rates charged to customers: | | |
| Depreciation and amortization in excess of capital cost allowance | 364 | 1,112 |
| RRPR variance account | 296 | 482 |
| Post-retirement and post-employment benefit expense in excess of cash payments | 223 | 201 |
| Losses carryforward | – | (870) |
| Change in valuation allowance | (516) | – |
| Environmental expenditures | (330) | (324) |
| Overheads capitalized for accounting but deducted for tax purposes | (104) | (141) |
| Pension contribution in excess of pension expense | (76) | (119) |
| Interest capitalized for accounting but deducted for tax purposes | (31) | (26) |
| Other | (27) | 72 |
| Net temporary differences | (201) | 387 |
| Net tax expense resulting from transition from PILs Regime to Federal Tax Regime | – | 5,000 |
| Prior year adjustments | (15) | (3) |
| Other permanent differences | 25 | (9) |
| Total income taxes / provision for PILs | (73) | 5,541 |

The major components of income tax expense (recovery) are as follows:

| Year ended December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Current income taxes / provision for (recovery of) PILs | (73) | 5,541 |
| Deferred income taxes / provision for PILs | – | – |
| Total income taxes / provision for (recovery of) PILs | (73) | 5,541 |
| | | |
| Effective income tax rate | (16.2%) | 882% |

The provision for PILs / current income taxes is remitted to, or received from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime), respectively. At December 31, 2016, the Company had $463 thousand receivable from the CRA (2015 – $37 thousand payable to the CRA) and $nil receivable from the OEFC (2015 – $327 thousand).

On October 31, 2015, the Company's exemption from tax under the Federal Tax Regime ceased to apply. Under the PILs Regime, the Company 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 Remote Communities making payments in lieu of tax (Departure Tax) totaling $5 million. To enable Hydro One Remote Communities to make the Departure Tax payment, Hydro One subscribed for 64 common shares of Hydro One Remote Communities for $5 million. The Company used the proceeds of this share subscription to pay the Departure Tax.

For the year ended December 31, 2016, the Company reported net income due to recognition of departure tax recovery. The following table presents a reconciliation of net income (loss) to net income under the cost recovery model to achieve breakeven net income:

| Year ended December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Net income before income taxes | 447 | 628 |
| Income taxes under cost-recovery model | 447 | 628 |
| Net income under cost-recovery model | – | – |
| Tax expense – Departure Tax | – | 5,000 |
| Tax recovery | (520) | (87) |
| Net income (loss) | 520 | (4,913) |

### 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, 2016 and 2015, deferred income tax assets and liabilities consisted of the following items:

| December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| **Deferred income tax assets (liabilities)** | | |
| Post-retirement and post-employment benefits expense in excess of cash payments | 5,440 | 5,038 |
| Environmental expenditures | 12,924 | 3,984 |
| Depreciation and amortization in excess of capital cost allowance | 6,617 | 7,548 |
| Regulatory amounts not recognized for tax | (14,358) | (5,803) |
| Other | (299) | (215) |
| | 10,324 | 10,552 |
| Less: Valuation allowance | (6,106) | (6,622) |
| Total deferred income tax assets | 4,218 | 3,930 |
| Less: current portion | – | 125 |
| | 4,218 | 3,805 |

During 2016 and 2015, there was no change in the rate applicable to deferred tax assets and liabilities. The valuation allowance for deferred tax assets as at December 31, 2016 was $6,106 thousand (2015 – $6,622 thousand). The valuation allowance primarily relates to temporary differences for non-depreciable assets. As at December 31, 2016, the Company has non-capital losses of $55 thousand, which would expire in 2036.

## 7. ACCOUNTS RECEIVABLE

| December 31, 2016 *(thousands of dollars)* | Current accounts receivable | Long-term accounts receivable | Total |
|---|---|---|---|
| Accounts receivable – billed | 3,396 | 702 | 4,098 |
| Accounts receivable – unbilled | 2,302 | – | 2,302 |
| Accounts receivable, gross | 5,698 | 702 | 6,400 |
| Allowance for doubtful accounts | (141) | (57) | (198) |
| Accounts receivable, net | 5,557 | 645 | 6,202 |

| December 31, 2015 *(thousands of dollars)* | Current accounts receivable | Long-term accounts receivable | Total |
|---|---|---|---|
| Accounts receivable – billed | 3,514 | 1,181 | 4,695 |
| Accounts receivable – unbilled | 1,077 | – | 1,077 |
| Accounts receivable, gross | 4,591 | 1,181 | 5,772 |
| Allowance for doubtful accounts | (156) | (111) | (267) |
| Accounts receivable, net | 4,435 | 1,070 | 5,505 |

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2016 and 2015:

| December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Allowance for doubtful accounts – January 1 | (267) | (304) |
| Write-offs | 69 | 67 |
| Adjustments to allowance for doubtful accounts | – | (30) |
| Allowance for doubtful accounts – December 31 | (198) | (267) |

## 8. PROPERTY, PLANT AND EQUIPMENT

| December 31, 2016 *(thousands of dollars)* | Property, Plant and Equipment[1] | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| Generation | 46,508 | 21,492 | 181 | 25,197 |
| Distribution | 10,542 | 2,234 | 476 | 8,784 |
| Administration and service | 12,496 | 2,904 | 53 | 9,645 |
| | 69,546 | 26,630 | 710 | 43,626 |

[1] Includes future use assets totalling $2,013 thousand.

| December 31, 2015 *(thousands of dollars)* | Property, Plant and Equipment[1] | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| Generation | 45,779 | 21,150 | 826 | 25,455 |
| Distribution | 9,780 | 2,049 | 312 | 8,043 |
| Administration and service | 11,716 | 2,594 | 50 | 9,172 |
| | 67,275 | 25,793 | 1,188 | 42,670 |

[1] Includes future use assets totalling $1,902 thousand.

Financing charges capitalized on property, plant and equipment under construction were $115 thousand in 2016 (2015 – $97 thousand).

## 9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

| December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| **Regulatory assets:** | | |
| Environmental | 35,845 | 11,051 |
| RRPR variance account | 1,644 | 2,760 |
| Post-retirement and post-employment benefits | 2,334 | 2,285 |
| Stock-based compensation | 318 | 99 |
| Total regulatory assets | 40,141 | 16,195 |
| Less: current portion | 1,183 | 1,483 |
| | 38,958 | 14,712 |
| **Regulatory liabilities:** | | |
| Deferred income tax regulatory liability | 4,218 | 3,930 |
| Total regulatory liabilities | 4,218 | 3,930 |
| Less: current portion | – | 125 |
| | 4,218 | 3,805 |

### Environmental

The Company 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 2016, the environmental regulatory asset increased by $25,732 thousand (2015 – decreased by $448 thousand) to reflect related changes in the Company's environmental liabilities. 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 Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2016 operation, maintenance and administration expenses would have been higher by $25,732 thousand (2015 – lower by $448 thousand). In addition, 2016 amortization expense would have been lower by $1,247 thousand (2015 – $1,222 thousand), and 2016 financing charges would have been higher by $309 thousand (2015 – $352 thousand).

### RRPR Variance Account

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2016, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of cumulative RRRP amounts received. In 2016, RRRP amounts received were higher than amounts required to achieve breakeven net income, and as such, the regulatory asset was reduced by $1,116 thousand (2015 – $1,818 thousand). In the absence of rate-regulated accounting, 2016 revenue would have been higher by $1,116 thousand (2015 – $1,818 thousand).

### Post-Retirement and Post-Employment Benefits

The Company 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, 2016 OCI would have been lower by $49 thousand (2015 – higher by $352 thousand).

### Stock-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2016 operation, maintenance and administration expenses would have been higher by $156 thousand (2015 – $69 thousand).

### Deferred Income Tax Regulatory 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 2016 income tax expense would have been higher by approximately $201 thousand (2015 – lower by $387 thousand).

## 10. LONG-TERM DEBT

The following table presents outstanding long-term debt at December 31, 2016 and 2015:

| December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| 3.02% note due 2026[1] | 10,000 | – |
| 5.38% note due 2036 | 23,000 | 23,000 |
| 4.19% note due 2044 | 10,000 | 10,000 |
| | 43,000 | 33,000 |
| Less: Deferred debt issuance costs[2] | (179) | (144) |
| Less: Net unamortized debt premiums[2] | (38) | (35) |
| Long-term debt | 42,783 | 32,821 |

1 On February 24, 2016, Hydro One Remote Communities issued a $10 million note wi h a maturity date of February 24, 2026 and a coupon rate of 3.02%. The note is payable to Hydro One.

2 Effective January 1, 2016, deferred debt issuance costs and net unamortized debt discounts were reclassified from other long-term assets as an offset to long-term debt upon adoption of ASU 2015-03 (see note 3). Balances as at December 31, 2015 were updated to reflect the retrospective adoption of ASU 2015-03.

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 *(thousands of dollars)* | Weighted Average Interest Rate *(%)* |
|---|---|---|
| 1 – 5 years | – | – |
| 6 – 10 years | 10,000 | 3.0 |
| Over 10 years | 33,000 | 5.0 |
| | 43,000 | 4.6 |

Interest payment obligations related to long-term debt are summarized by year in the following table:

| Year | Interest Payments *(thousands of dollars)* |
|---|---|
| 2017 | 1,958 |
| 2018 | 1,958 |
| 2019 | 1,958 |
| 2020 | 1,958 |
| 2021 | 1,958 |
| | 9,790 |
| 2022-2026 | 9,642 |
| 2027+ | 19,089 |
| | 38,521 |

### 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.

Hydro One Remote Communities 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 Remote Communities 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, 2016 and 2015, the Company's 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 Hierarchy**

The fair value hierarchy of financial assets and liabilities at December 31, 2016 and 2015 is as follows:

| December 31, 2016 *(thousands of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Inter-company demand facility | 7,253 | 7,253 | 7,253 | – | – |
| | 7,253 | 7,253 | 7,253 | – | – |
| **Liabilities:** | | | | | |
| Long-term debt | 42,783 | 48,588 | – | 48,588 | – |
| | 42,783 | 48,588 | – | 48,588 | – |

| December 31, 2015 *(thousands of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 6,056 | 6,056 | 6,056 | – | – |
| Long-term debt | 32,821 | 37,957 | – | 37,957 | – |
| | 38,877 | 44,013 | 6,056 | 37,957 | – |

The fair value 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, 2016 and 2015.

**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 related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2016 and 2015, 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 Remote Communities did not earn a significant amount of revenue from any single customer. At December 31, 2016 and 2015, there was no significant accounts receivable balance due from any single customer.

At December 31, 2016, the Company's provision for bad debts was $197 thousand (2015 – $267 thousand). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2016, approximately 40% (2015 – 44%) of the Company's net accounts receivable were aged more than 60 days. The Company's 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. Hydro One Remote Communities 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, 2016, accounts payable and accrued liabilities in the amount of $7,626 thousand (2015 – $5,721 thousand) are expected to be settled in cash at their carrying amounts within the next 12 months.

## 12. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplementary pension plan, and post-retirement and post-employment benefit plans.

**Defined Contribution Pension Plan**

Hydro One established a DC Plan effective January 1, 2016. The DC Plan is mandatory and covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

The Company's contributions to the DC Plan for the year ended December 31, 2016 were $8 thousand (2015 – $nil). At December 31, 2016, Company contributions payable included in accrued liabilities on the Balance Sheets were less than $1 thousand (2015 – $nil).

### Defined Benefit Pension Plan

The Pension Plan is a defined benefit contributory plan which covers all regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for 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. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2016 of $108 million (2015 – $177 million) were based on an actuarial valuation effective December 31, 2015 (2015 – based on an actuarial valuation effective December 31, 2013) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2017 and 2018 are approximately $105 million and $102 million, respectively, based on the actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings. Future minimum contributions beyond 2018 will be based on an actuarial valuation effective no later than December 31, 2018. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Hydro One Supplemental Pension Plan (Supplemental 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 Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Balance Sheets.

At December 31, 2016, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,774 million (2015 – $7,683 million). The fair value of pension plan assets available for these benefits was $6,874 million (2015 – $6,731 million).

### Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2016, Hydro One Remote Communities charged $866 thousand (2015 – $759 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $347 thousand (2015 – $325 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2016 were $63 thousand (2015 – $51 thousand). In addition, the incremental offset to increase the associated post-retirement and post-employment benefits regulatory assets by $49 thousand (2015 – $351 thousand decrease) was recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

| December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Accrued liabilities | 400 | 373 |
| Post-retirement and post-employment benefit liability | 14,689 | 13,517 |
| | 15,089 | 13,890 |

## 13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2016 and 2015:

| Year ended December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Environmental liabilities, January 1 | 11,051 | 12,369 |
| Interest accretion | 309 | 352 |
| Expenditures | (1,247) | (1,222) |
| Revaluation adjustment | 25,732 | (448) |
| Environmental liabilities, December 31 | 35,845 | 11,051 |
| Less: current portion | 1,183 | 1,483 |
| | 34,662 | 9,568 |

The following table shows 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 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Undiscounted environmental liabilities | 37,286 | 11,474 |
| Less: discounting accumulated liabilities to present value | 1,441 | 422 |
| Discounted environmental liabilities | 35,845 | 11,051 |

At December 31, 2016, the estimated future environmental expenditures were as follows:

| *(thousands of dollars)* | |
|---|---|
| 2017 | 1,183 |
| 2018 | 1,073 |
| 2019 | 1,794 |
| 2020 | 3,628 |
| 2021 | 3,203 |
| Thereafter | 26,405 |
| | 37,286 |

The Company records a liability for the estimated future expenditures for the contaminated LAR 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 3.6%, 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.

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $37,286 thousand (2015 – $11,474 thousand). These expenditures are expected to be incurred over the period from 2017 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2016 to increase the LAR environmental liability by $25,732 thousand (2015 – decrease of $448 thousand).

## 14. SHARE CAPITAL

### Common Shares

The Company has 267 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

The following table presents the movement in common shares during the year ended December 31, 2015. There was no movement in common shares during the year ended December 31, 2016.

| *(number of common shares)* | |
|---|---|
| Number of common shares – January 1, 2015 | 2 |
| Share split *(a)* | 200 |
| Common shares issued *(b)* | 64 |
| Common shares issued *(c)* | 1 |
| Number of common shares – December 31, 2015 | 267 |

(a) On November 2, 2015, all of the issued and outstanding common shares of Hydro Once Remote Communities were changed into 202 issued and outstanding common shares of the Company.

(b) On November 4, 2015, Hydro One Remote Communities issued 64 common shares to Hydro One for proceeds of $5 million.

(c) On November 3, 2015, Hydro One Remote Communities declared a stock dividend on its common shares, which due to the number of shares issued and the resulting effect on the price per share was treated as a stock split. On November 5, 2015, Hydro One Remote Communities effected a reverse split and issued as consideration one common share to Hydro One. There was no impact to the capital structure of Hydro One Remote Communities as a net result of the stock dividend and the reverse split.

### Dividends

The Company does not pay dividends under its breakeven business model.

## 15. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited; however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Remote communities, in current and future periods.

### Share Grant Plans

At December 31, 2016, Hydro One Limited had two share grant plans (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). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 plan was 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees of Hydro One Remote Communities.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The 2015 fair value of Hydro One Limited shares granted to employees of Hydro One Remote Communities was $1,091 thousand. The fair value was estimated based on the grant date Hydro One Limited 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. No shares were granted under the Share Grant Plans in 2016. Total stock-based compensation recognized during 2016 by Hydro One Remote Communities was $219 thousand (2015 – $99 thousand) and was recorded as a regulatory asset.

A summary of Hydro One Remote Communities' share grant activity under the Share Grant Plans during years ended December 31, 2016 and 2015 is presented below:

| Year ended December 31, 2016 | Share Grants *(Number of common shares)* | Weighted-Average Price |
|---|---|---|
| Share grants outstanding – January 1 | 53,196 | $20.50 |
| Granted (non-vested) | – | – |
| Share grants forfeited | (9) | $20.50 |
| Share grants transferred in[1] | 3,455 | $20.50 |
| Share grants transferred out[2] | (2,921) | $20.50 |
| Share grants outstanding – December 31 | 53,721 | $20.50 |

[1] Share grants transferred in relate to PWU employees transferred from Hydro One Networks to Hydro One Remote Communities. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

[2] Share grants transferred out relate to PWU employees transferred from Hydro One Remote Communi ies to Hydro One Networks. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

| Year ended December 31, 2015 | Share Grants *(Number of common shares)* | Weighted-Average Price |
|---|---|---|
| Share grants outstanding – January 1 | – | – |
| Granted (non-vested) | 53,196 | $20.50 |
| Share grants outstanding – December 31 | 53,196 | $20.50 |

**Employee Share Ownership Plan**

Effective December 15, 2015, Hydro One Limited 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 Limited. The Company matches 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. In 2016, Company contributions made under the ESOP were $19 thousand (2015 – $nil).

**Long-term Incentive Plan**

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited 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 of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other stock-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

During 2016, Hydro One Limited granted awards under its LTIP to employees of Hydro One Remote Communities, consisting of PSUs and RSUs, all of which are equity settled in Hydro One Limited shares, as follows:

| Year ended December 31, 2016 | Number of PSUs | Number of RSUs |
|---|---|---|
| Units outstanding – January 1 | – | – |
| Units granted | 2,581 | 2,729 |
| Units forfeited | – | – |
| Units outstanding – December 31 | 2,581 | 2,729 |

The grant date total fair value of the awards was $133 thousand (2015 – $nil). The compensation expense recognized by the Company relating to these awards during 2016 was $21 thousand (2015 – $nil).

## 16. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited, and the Province is the majority shareholder of Hydro One Limited. The IESO and OEFC are related parties to Hydro One Remote Communities because they are controlled or significantly influenced by the Province.

| | | Year ended December 31 | |
|---|---|---|---|
| | | 2016 | 2015 |
| Related Party | Transaction | *(thousands of dollars)* | |
| IESO | Supply of electricity to remote northern communities – amounts received[1] | 32,259 | 32,259 |
| OEFC | Departure tax payment | – | 5,000 |
| Hydro One Limited and its subsidiaries | Common shares issued[2] | – | 5,000 |
| | Revenues related to the provision of services[3] | 469 | 213 |
| | Costs expensed related to purchase of services[3] | 2,965 | 2,973 |
| | Interest expense on long-term debt | 1,915 | 1,655 |
| | Interest expense (income) on inter-company demand facility | (48) | 65 |
| | Stock-based compensation costs | 219 | 99 |

[1] Consistent with the break even business model, the Company recognized $31,143 thousand as RRRP revenue in 2016 (2015 – $30,441 thousand), with the difference recorded in the regulatory asset RRPR variance account.

[2] On November 4, 2015, Hydro One Remote Communities issued 64 common shares to Hydro One for proceeds of $5 million.

[3] The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services.

Transactions with related parties are 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 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Inter-company demand facility | 7,253 | (6,056) |
| Accrued interest | 280 | 172 |
| Accounts receivable | – | 95 |
| Income tax receivable | – | 327 |

## 17. STATEMENTS OF CASH FLOWS

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

| Year ended December 31 *(thousands of dollars)* | 2016 | 2015 |
|---|---|---|
| Accounts receivable | (1,122) | 19 |
| Fuel, materials and supplies | 264 | (648) |
| Income taxes receivable | (136) | 2,356 |
| Long-term accounts receivable | 425 | 180 |
| Other assets | (24) | – |
| Accounts payable | 39 | 468 |
| Accrued liabilities | 2,231 | (4,741) |
| Accrued interest | 108 | – |
| Income taxes payable | (37) | 37 |
| Post-retirement and post-employment benefit liability | 1,123 | 1,007 |
| | 2,871 | (1,322) |
| **Supplementary information:** | | |
| Net interest paid | 1,807 | 1,655 |
| Taxes paid | – | 5,000 |

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid are fully recovered.

## 18. CONTINGENCIES

### Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

Hydro One and three of its subsidiaries, including Hydro One Remote Communities, are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. A certification motion in the class action is pending. 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 Hydro One 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, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One 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 2016, Hydro One paid approximately $1 million (2015 – $1 million) in respect of consents obtained. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One 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 Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

## 19. COMMITMENTS

### Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years. During the year ended December 31, 2016, the Company made lease payments totalling $120 thousand (2015 – $120 thousand). The following table presents a summary of Hydro One Remote Communities' commitments under lease agreements due in the next 5 years and thereafter.

| December 31, 2016 *(thousands of dollars)* | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Thereafter |
|---|---|---|---|---|---|---|
| Operating lease commitments | 120 | 150 | 150 | 150 | 150 | 150 |

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To Board of Directors of Hydro One Remote Communities Inc.

As specifically agreed, we have performed the specified auditing procedures below in connection with your filing of financial information with the Ontario Energy Board with respect to adjustments from the audited financial statements of Hydro One Remotes Communities Inc. to the 'Regulated' Hydro One Remotes financial information as at and for the year ended December 31, 2016 (hereinafter referred to "financial information") of Hydro One Remote Communities Inc. ("the Entity" or "Hydro One Remotes"). The specified auditing procedures are summarized, along with the findings, as follows:

| **Specified Auditing Procedures Performed** | **Findings** |
|---|---|
| 1) Obtain from Hydro One Remote Communities Inc. ("Hydro One Remotes") the reconciliation from the audited financial statements of Hydro One Remotes to the 'Regulated' Hydro One Remotes financial information, as follows:<br>a) Balance Sheet as at December 31, 2016<br>b) Net income and other comprehensive income for the year ended December 31, 2016 | No exceptions |
| 2) Obtain the analyses and documents prepared by Hydro One Remotes management supporting each of the adjustments identified in the reconciliation obtained in procedure 1. | No exceptions |
| 3) Trace the reconciliation balances as follows:<br>a) Agree the "2016 audited financial statements" column to the audited financial statements of Hydro One Remotes as at and for the period ended December 31, 2016;<br>b) Agree the "Non Regulated Segment" column to the analysis and documents prepared by Hydro One Remotes management obtained in procedure 2;<br>c) Recalculate the "Regulated Segment" based on amounts in procedures 3(a) and 3(b). | No exceptions |

We make no representation regarding the appropriateness and sufficiency of the specified auditing procedures. These specified auditing procedures do not constitute an audit or review of the financial information, and therefore we are unable to and do not provide any assurance on financial information of the Entity.

Our report is intended solely for the Board of Directors of the Entity and the Ontario Energy Board and should not be distributed or used by parties other than Board of Directors of Hydro One Remote Communities Inc. and the Ontario Energy Board.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
April 28, 2017
Toronto, Canada

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS**

| At December 31, 2016 (thousands of Canadian dollars) | 2016 Audited Financial Statements | Non Regulated Segment | | Regulated Segment |
|---|---|---|---|---|
| **Assets** | | | | |
| Current assets: | | | | |
| Inter-company demand facility | 7,253 | - | | 7,253 |
| Accounts receivable | 5,557 | - | | 5,557 |
| Regulatory assets | 1,183 | - | | 1,183 |
| Fuel, materials and supplies | 2,476 | | | 2,476 |
| Income taxes receivable | 463 | 607 | A | - |
| | | (144) | D | |
| | 16,932 | 463 | | 16,469 |
| Property, plant and equipment | 43,626 | - | | 43,626 |
| Other long-term assets: | | | | - |
| Regulatory assets | 38,958 | - | | 38,958 |
| Deferred income tax assets | 4,218 | - | | 4,218 |
| Long-term accounts receivable | 645 | - | | 645 |
| Other assets | 24 | - | | 24 |
| | 43,845 | - | | 43,845 |
| **Total assets** | **104,403** | **463** | | **103,940** |
| **Liabilities** | | | | |
| Current liabilities: | | | | |
| Accounts payable | 1,383 | - | | 1,383 |
| Accrued liabilities | 6,309 | - | | 6,309 |
| Accrued interest | 280 | - | | 280 |
| Income taxes payable | - | 144 | D | 144 |
| | 7,972 | 144 | | 8,116 |
| Long-term liabilities: | | | | |
| Long-term debt | 42,783 | - | | 42,783 |
| Post-retirement and post-employment benefit liability | 14,689 | - | | 14,689 |
| Regulatory liabilities | 4,218 | - | | 4,218 |
| Environmental liabilities | 34,662 | - | | 34,662 |
| | 96,352 | - | | 96,352 |
| **Total liabilities** | **104,324** | **144** | | **104,468** |
| **Shareholder's equity (deficit)** | | | | |
| Common shares | 5,000 | 5,000 | B | - |
| Deficit | (4,393) | (4,393) | C | - |
| Accumulated other comprehensive loss | (528) | - | | (528) |
| **Total shareholder's equity (deficit)** | **79** | **607** | | **(528)** |
| **Total liabilities and shareholder's equity (deficit)** | **104,403** | **607** | | **103,940** |

**Notes:**

A - Income tax receivable relating to utilization of the non regulated Deferred Tax Asset

B - Injection of equity by Shareholder (Hydro One Inc.) to fund Departure Tax

C - Departure Tax expense and tax recovery relating to utilization of the non regulated Deferred Tax Asset

D - Reclassification to Income tax payable subsequent to adjustmnet **A**

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

| Year ended December 31, 2016 *(thousands of Canadian dollars)* | 2016 Audited Financial Statements | Non Regulated Segment | Regulated Segment |
|---|---|---|---|
| **Revenues** | 50,357 | - | 50,357 |
| **Costs** | | | |
| Operation, maintenance and administration | 19,826 | - | 19,826 |
| Fuel used for electric generation | 23,669 | - | 23,669 |
| Depreciation and amortization | 4,618 | - | 4,618 |
| | 48,113 | - | 48,113 |
| **Income before financing charges and income taxes** | **2,244** | - | **2,244** |
| Financing charges | 1,797 | - | 1,797 |
| **Income before income taxes** | **447** | - | **447** |
| Income tax expense (recovery) | (73) | (520) A | 447 |
| **Net income (loss)** | **520** | **520** | - |
| Other comprehensive income | 14 | - | 14 |
| **Comprehensive income (loss)** | **534** | **520** | **14** |

**Note:**
A - Tax recovery relating to utilization of the non regulated Deferred Tax Asset

## Hydro One Remote Communities Inc.

### Financial Statements Reconciled to USofA Trial Balance 2016
### For year ending December 31, 2016 (in $K)

| Financial Statement Item | USofA Accounts | Total per Exhibit A-7-2 Attachment 4 | Adjustments A | B | C | D | USofA Balance Sheet |
|---|---|---|---|---|---|---|---|
| **Assets** | | | | | | | |
| Current assets: | | | | | | | |
| Inter-company demand facility | 1200 | 7,253 | | | | | 7,253 |
| Accounts receivable | 1100, 1105, 1110, 1130, 1180 | 5,557 | | | | | 5,557 |
| Regulatory assets | 1525 | 1,183 | | | | | 1,183 |
| Fuel, materials and supplies | 1305, 1330 | 2,476 | | | | | 2,476 |
| Deferred income tax assets | 1190 | - | | | | | - |
| Income taxes receivable | 2294 | 463 | (607) | | 185 | | 41 |
| | | 16,932 | (607) | - | 185 | - | 16,510 |
| Property, plant and equipment | | 43,626 | | (43,626) | | | - |
| Generation plant | 1615, 1620, 1650, 1665, 1670, 1675, 1680, 1685 | | | 45,995 | | | 45,995 |
| Distribution plant | 1805, 1806, 1830, 1835, 1845, 1850, 1860 | | | 9,097 | | | 9,097 |
| General plant | 1908, 1910, 1915, 1920, 1935, 1940, 1945, 1955, 1960 | | | 12,441 | | | 12,441 |
| Less: accumulated depreciation | 2105 | | | 26,630 | | | 26,630 |
| | | 43,626 | - | (2,723) | - | - | 40,903 |
| Construction in progress | 2055 | | | 710 | | | 710 |
| Future use components and spares | 2040 | | | 2,013 | | | 2,013 |
| Property, plant and equipment | | 43,626 | - | - | - | - | 43,626 |
| Other long-term assets: | | | | | | | |
| Regulatory assets | 1460, 1508, 1525 | 38,958 | | | (185) | | 38,773 |
| Deferred income tax assets | 1460 | 4,218 | | | | | 4,218 |
| Long-term accounts receivable | 1460 | 645 | | | | | 645 |
| Other assets | 1460 | 24 | | | | (24) | - |
| Deferred debt costs | 1425 | | | | | 180 | 180 |
| Net unamortized debt discounts | 2520 | | | | | 62 | 62 |
| | | 43,845 | - | - | (185) | 218 | 43,878 |
| **Total assets** | | **104,403** | **(607)** | **-** | **-** | **218** | **104,014** |
| **Liabilities** | | | | | | | |
| Current liabilities: | | | | | | | |
| Inter-company demand facility | 2240 | - | | | | | - |
| Accounts payable | 2205 | 1,383 | | | | | 1,383 |
| Accrued liabilities | 2220, 2210, 2215, 2250, 2290, 2292, 2294, 2296 | 6,309 | | | | | 6,309 |
| Accrued interest | 2268 | 280 | | | | | 280 |
| Regulatory liabilities | 2220 | - | | | | | - |
| Income taxes payable | 2294 | - | | | | | - |
| | | 7,972 | - | - | - | - | 7,972 |
| Long-term liabilities: | | | | | | | |
| Long-term debt | 2520 | 42,783 | | | | 218 | 43,001 |
| Post-retirement and post-employment liability | 2306 | 14,689 | | | | | 14,689 |
| Regulatory liabilities | 2350 | 4,218 | | | | | 4,218 |
| Environmental liabilities | 2320 | 34,662 | | | | | 34,662 |
| | | 96,352 | - | - | - | 218 | 96,570 |
| **Total liabilities** | | **104,324** | **-** | **-** | **-** | **218** | **104,542** |
| **Shareholder's equity (deficit)** | | | | | | | |
| Common shares | 3005 | 5,000 | (5,000) | | | | - |
| Balance transferred from income | 3046 | (4,393) | 4,393 | | | 14 | 14 |
| Accumulated other comprehensive income | 3090 | (528) | | | | (14) | (542) |
| **Total shareholder's equity (deficit)** | | **79** | **(607)** | **-** | **-** | **-** | **(528)** |
| **Total liabilities and shareholder's equity (deficit)** | | **104,403** | **(607)** | **-** | **-** | **218** | **104,014** |

**A** Income tax receivable relating to utilization of the non regulated Deferred Tax Asset, injection of equity to fund departure taxes, Departure Tax expense and tax recovery relating to utilization of the non regulated Deferred Tax Asset
**B** Reallocation of property, plant and equipment to specified categories - refer to Note 8 in Annual Financial Statements, and reallocation of generation, distribution and general plant to components and spares
**C** Reallocation of corporate income taxes
**D** Reallocation of unamortized debt expense and balance transferred from income

**Hydro One Remote Communities Inc.**

**Financial Statements Reconciled to USofA Trial Balance 2016**
**For year ending December 31, 2016 (in $K)**

| Financial Statement item | USofA Accounts | Total per Exhibit A-7-2 Attachment 4 | Adjustments A | Adjustments B | Adjustments C | Utility Income |
|---|---|---|---|---|---|---|
| **Revenue** | | | | | | |
| Energy sales | 4006, 4010, 4025, 4062 | 17,659 | | | | 17,659 |
| Rural rate protection | 4245 | 31,143 | | | | 31,143 |
| Other Revenue | 4225, 4235, 4325, 6035 | 1,555 | | | | 1,555 |
| **Revenues** | | **50,357** | **-** | **-** | **-** | **50,357** |
| **Costs** | | | | | | |
| Other power supply expenses | 4708 | - | 61 | | | 61 |
| Fuel used for electric generation | 4510 | 23,669 | | | | 23,669 |
| Operation, maintenance and administration | | 19,826 | (61) | | | 19,765 |
| Operation | 4550, 4555, 5085 | 4,631 | (61) | | | 4,570 |
| Maintenance | 4610, 4635, 5120, 5125, 5130, 5135, 5175 | 11,354 | | | | 11,354 |
| Billing and collecting | 5310, 5315, 5320, 5335, 6205 | 1,926 | | | | 1,926 |
| Community relations | 5410, 5415, 5420 | 137 | | | | 137 |
| Administrative and general expenses | 4330, 5615, 5625, 5655, 5675 | 1,778 | | | | 1,778 |
| Depreciation and amortization | 5705, 5715 | 4,618 | | (1,247) | | 3,371 |
| | | **48,113** | **-** | **(1,247)** | **-** | **46,866** |
| **Income before financing and income taxes** | | **2,244** | **-** | **1,247** | **-** | **3,491** |
| Financing charges | 6005, 6010, 6035, 6040 | 1,797 | | 1,247 | | 3,044 |
| **Income before income taxes** | | **447** | **-** | **-** | **-** | **447** |
| Income tax expense (recovery) | 6110 | (73) | | | (520) | 447 |
| **Net income (loss)** | | **520** | **-** | **-** | **520** | **-** |
| Other comprehensive income | 3046 | 14 | | | | 14 |
| **Other comprehensive income (loss)** | | **534** | **-** | **-** | **520** | **14** |

**A** Other power supply expenses grouped in operation, maintenance and administration
**B** Regulatory assets amortization reallocated from depreciation and amortization line
**C** Tax recovery relating to utilization of the non regulated Deferred Tax Asset

# HYDRO ONE INC. HISTORICAL YEARS ANNUAL REPORTS
# (2013, 2014, 2015, 2016)

Attachment 1: Hydro One Annual Report 2013
Attachment 2: Hydro One Annual Report 2014
Attachment 3: Hydro One Annual Report 2015
Attachment 4: Hydro One Annual Report 2016

hydro One

# ANNUAL REPORT 2013

Every day Hydro One employees go to extraordinary lengths to take care of our customers and each other. During the December 2013 ice storm, 1,400 employees answered the call and gave up time with their families to get the lights back on.

We are committed to providing Ontarians with safe, reliable and affordable power 24/7, 365 days a year.

**Ontarians rely on us and we deliver. Each and every day.**

Serving our customers isn't just about answering the phone and driving a truck. It's about climbing a pole in freezing temperatures to restore power. It's about stopping at the side of the road to help our customers. It's any time we interact with anyone outside our Company.

**81%**

Customer Satisfaction (Transmission Customers)

**87%**

Customer Satisfaction (Distribution Customers)

Cover photo courtesy of CTV News Barrie.

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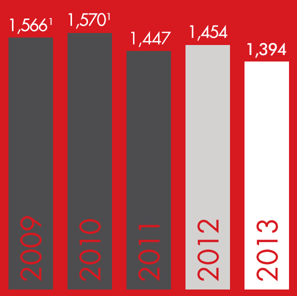
## CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

### CAPITAL INVESTMENTS

(CAD $ millions)

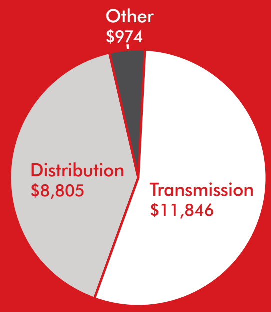



[1] based on Canadian GAAP

### TOTAL ASSETS

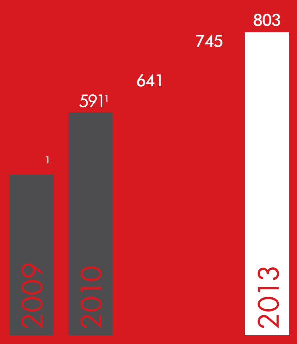
December 31, 2013

(CAD $ millions)




### NET INCOME

(CAD $ millions)




[1] based on Canadian GAAP

**Year ended December 31, 2013**

| *(CAD $ millions, except as otherwise noted)* | 2013 | 2012 | $ Change | % Change |
|---|---|---|---|---|
| Revenues | **6,074** | 5,728 | 346 | 6 |
| Purchased power | **3,020** | 2,774 | 246 | 9 |
| Operating costs | **1,782** | 1,730 | 52 | 3 |
| Net income | **803** | 745 | 58 | 8 |
| Net cash from operating activities | **1,404** | 1,294 | 110 | 9 |
| Average annual Ontario 60-minute peak demand *(MW)*[1] | **21,493** | 21,132 | 361 | 2 |
| Distribution – units distributed to customers *(TWh)*[1] | **29.8** | 29.2 | 0.6 | 2 |

[1] System-related statistics are preliminary.

> "The Company continued its investments in the province's electricity system for the benefit of all Ontarians, as well as strengthening its commitment to provide a firm business model to its sole shareholder, the Province of Ontario."

# LETTER FROM THE CHAIR

Hydro One's commitment to delivering safe, reliable and affordable electricity to the people of Ontario remained foremost in our minds in 2013.

The Company continued its investments in the province's electricity system for the benefit of all Ontarians, as well as strengthening its commitment to provide a firm business model to its sole shareholder, the Province of Ontario.

From a financial standpoint, the year was a great success. Hydro One's net income reached $803 million for the year, compared to $745 million in 2012.

The 8 per cent increase was mainly due to efforts to reduce operating, maintenance and administrative costs. Additionally, the Company experienced higher revenues largely due to an increase in the Ontario Energy Board's regulated price plan rate-setting process and the Independent Electricity System Operator's spot market. Higher energy consumption and peak demand in the summer and winter months also contributed to higher revenues.

The Company's capital investments reached $1,394 million in 2013 due to the severe summer and winter storms, as well as investments in several infrastructure projects, including the completion of the Commerce Way Transformer Station and the Summerhaven 230 kV Switching Station.

Hydro One paid dividends of $218 million to the Province in 2013, and recorded a provision of $109 million for payments in lieu of corporate income taxes.

Our Company's response to the severe storms in 2013, particularly Toronto's July flood and December ice storm, is something of which we can all be proud.

While we continued to demonstrate our ability to deliver safe and reliable electricity and to provide excellent returns to our shareholder, affordability for our customers is a cause for concern. The Province's 2013 Long-Term Energy Plan (LTEP) indicates that electricity prices will continue to rise. While this increase will be caused more by the cost of the electricity itself rather than by our delivery charges, we will have to be even more vigilant as to our costs going forward.

There were important strategic successes during the year:

1. The LTEP designated our Company to develop and seek approval for the Northwest Bulk Transmission Line Project, a significant reinforcement of the transmission system in the area west of Thunder Bay.

2. The Board of Directors approved a robust, but prudent, local distribution company (LDC) consolidation strategy to facilitate consolidation of Ontario's distribution sector. The agreement reached by our Company in 2013 to acquire Norfolk Power was an important first step in pursuing this strategy.

There was, however, a serious disappointment. In May 2013, our Company transitioned to a new customer billing system, a project over which the Board had detailed oversight. Some of our distribution customers experienced prolonged billing and related service issues as a result of the transition to the new system to a degree that was surprising and, indeed, unacceptable. This has led to an investigation by the provincial Ombudsman. However, the Board is confident that senior management is entirely focused on resolving these issues and delivering the service that our customers have a right to expect. Board oversight on this matter will remain a priority in 2014.

I would like to thank all Hydro One employees and my colleagues on the Board for their dedication and commitment to the Company and to the people of Ontario.

**James Arnett**
Chair of the Board of Directors

“During the December ice storm, more than 585,000 customers were affected, with 1,400 Hydro One employees working around the clock to repair the damage caused by freezing rain and to restore electricity service to our customers.”

# LETTER FROM THE PRESIDENT AND CEO

Our Company’s success is determined by how well we serve the people of Ontario. Every employee who wears the Hydro One logo goes to work every day knowing that people count on us to make sure that electricity travels safely and reliably from where it’s generated to where it’s used to power life.

In 2013, we focused on improving our customer service and demonstrating excellence in running our business.

Serving our customers well often means responding in times of emergency. In a year of unprecedented storms, Hydro One employees worked quickly and safely to restore power to 2,556,000 customers affected by nine large storms that brought record rainfall, high winds and severe ice conditions.

During the December ice storm, more than 585,000 customers were affected, with 1,400 Hydro One employees working around the clock to repair the damage caused by freezing rain and to restore electricity service to our customers.

In May, we launched our new Customer Information System to replace a system that was no longer supported and had reached the end of its useful life. For 95 per cent of our customers, the move to the new system was seamless. But for about five per cent of our customers, the new system caused errors and we did not move quickly enough to solve their problems. These service issues will ultimately be resolved and Hydro One will continue to work to restore the confidence of these customers.

We are also measured by how well we perform as a commercial business, an important part of our mandate from the Province. Hydro One continued to demonstrate its value to the Province, exceeding its financial targets and working to control costs by improving the efficiency of our work programs and negotiating increased pension contribution ratios with two of our unions and our management employees.

During 2013, we made capital investments of $1,394 million to improve system reliability, to address our aging power system so we can improve service to our customers and to facilitate the connection of new generation.

I would like to thank our Board of Directors for their support, my leadership team for their dedication to improving our Company and our employees for their commitment to working safely in the service of our customers.

**Carmine Marcello**
President and Chief Executive Officer

# SAFETY

## EVERY DAY RESPONSIBILITY: FOR OUR SAFETY AND YOURS

Safety each and every day means a commitment to a workplace where all employees work together to ensure a safe work environment for all. It means looking out for one another just as much as it means staying alert and focused on the job at hand. We work safely to deliver the ultimate value to our customers. Power.

Hydro One was certified in the internationally recognized Occupational Health and Safety Assessment Series (OHSAS) 18001 standard on June 28, 2013 after an 18-month effort.

## We have nothing without safety.

**INJURY-FREE WORKPLACE**

2.5 medical attentions per 200,000 hours worked in 2013

The electricity industry is an unforgiving, potentially hazardous environment where a single wrong move could result in a series of dangerous events.

To make sure every employee goes home safe and sound, Hydro One is committed to fostering a work environment where health and safety are the top priorities each and every day. This work culture guarantees that the right people are trained for the right jobs. It also maintains the safety of all Hydro One employees and Ontarians.

## OHSAS 18001 CERTIFICATION

In June 2013, Hydro One was certified in the internationally recognized Occupational Health and Safety Assessment Series (OHSAS) 18001 standard. This prestigious certification further enforces the Company's commitment to creating a culture of zero workplace injuries. It is also a significant milestone in our history in sustaining our world-class Health and Safety management system.

## HEALTH AND SAFETY PERFORMANCE RECOGNITION

The aim of the 2013 Health and Safety Performance Recognition program was to celebrate individual and team safety milestone achievements throughout the Company, as well as to improve the employee health and safety performance recognition process.

## INJURY-FREE WORKPLACE

Hydro One has seen a steady decrease in both "near misses" (high Maximum Reasonable Potential for Harm incidents) and the number of preventable motor vehicle accidents year-over-year. As in previous years, Hydro One used medical attentions as a performance indicator to measure its injury-free workplace goal in 2013. This is in line with the Company's strategic objectives and its Journey to Zero initiatives.

Medical attentions are defined as injuries that require treatment by a medical practitioner and are reported to the Workplace Safety and Insurance Board. The indicator is calculated as the number of attentions per 200,000 hours worked. In 2013, Hydro One reported 2.5 incidents per 200,000 hours worked.

# EVERY DAY RELIABILITY: BUILDING AND MAINTAINING OUR INFRASTRUCTURE

We bring knowledge, commitment and dedication to the work that we do. We work through holidays to get the power back on. We stop at the side of a road to talk to customers. We do more than just keep the lights on.

On April 2, 2013, our Company reached an agreement with Norfolk County to acquire Norfolk Power.

**12.9**
(minutes/delivery point)

Duration of customer unplanned interruptions on 115/230 kV network transmission system per all multi-circuit supplied delivery points

**6.9**
(hours per customer)

Duration of customer interruptions on the distribution system

The word "reliability" has been important every year in our history. This past year was proof. From wind storms and torrential rain to an ice storm at the end of December, Mother Nature tested our emergency response efforts in 2013.

## PURCHASE OF NORFOLK POWER

In April, we reached an agreement with Norfolk County to purchase Norfolk Power.

## POLE REPLACEMENT PROGRAM

In 2013, we replaced 11,000 wood poles across our 123,000-kilometre distribution system in an effort to maintain system reliability and promote public safety. The $82 million program is an investment in Ontario's energy future.

## SUMMERHAVEN 230 KV SWITCHING STATION

In June 2013, our Summerhaven 230 kV Switching Station was energized in Haldimand County. Work began in 2012 and involved the construction of a greenfield station to connect the Summerhaven Wind Farm Centre under Ontario's Green Energy Act. At maximum generating capacity, the 124 MW centre can produce enough clean energy to power approximately 32,000 homes.

## STORM RESTORATION

Ontario was hit with an onslaught of severe storms throughout 2013, causing power disruptions and at times, lengthy outages. We worked 24/7 to restore power to our customers.

**Storm highlights include:**

- In January, crews restored power to 48,000 customers after winter storms caused a number of outages.
- In April, crews restored power to more than 150,000 customers after high winds and freezing rain caused widespread damage.
- In July, crews restored power to more than 400,000 Toronto homes and businesses after heavy rains caused severe flooding at our Richview and Manby transmission stations.
- In November, crews worked for three days straight to restore power to more than 315,000 customers after a wind storm caused significant damage to our distribution system.
- In December, an ice storm that hit parts of Ontario downed power lines and caused widespread power outages. Between December 21 and December 29, approximately 585,000 customers were without power. We worked with local utilities to get customers back on line and by December 27, 98 per cent of affected customers had their power restored.

## MODERNIZING THE GRID

Our focus continues on the Advanced Distribution System (ADS) – smart grid initiatives that consist of a wireless communication network and various intelligent electronic devices (IEDs) – to improve reliability and operations, renewable energy integration and provide timely information to help customers better manage their electricity costs.

In terms of our micro-fit initiatives and distributed generation, we connected 1,414 projects in 2013. The 2013 projects calculate to about 12,904 kW. Since December 2010, we've connected 11,329 projects, which calculates to about 109 MW in renewable power, through our clean and renewable energy programming.

Another key step in grid modernization is the reinforcement of our transmission system. Ontario's Long-Term Energy Plan announcement that we will develop and seek approval for the Northwest Bulk Transmission Line Project, west of Thunder Bay, demonstrates the Province's trust in our ability to improve reliability in the north.

# INNOVATION & PRODUCTIVITY

## EVERY DAY INNOVATION: COMMITTED TO THE FUTURE

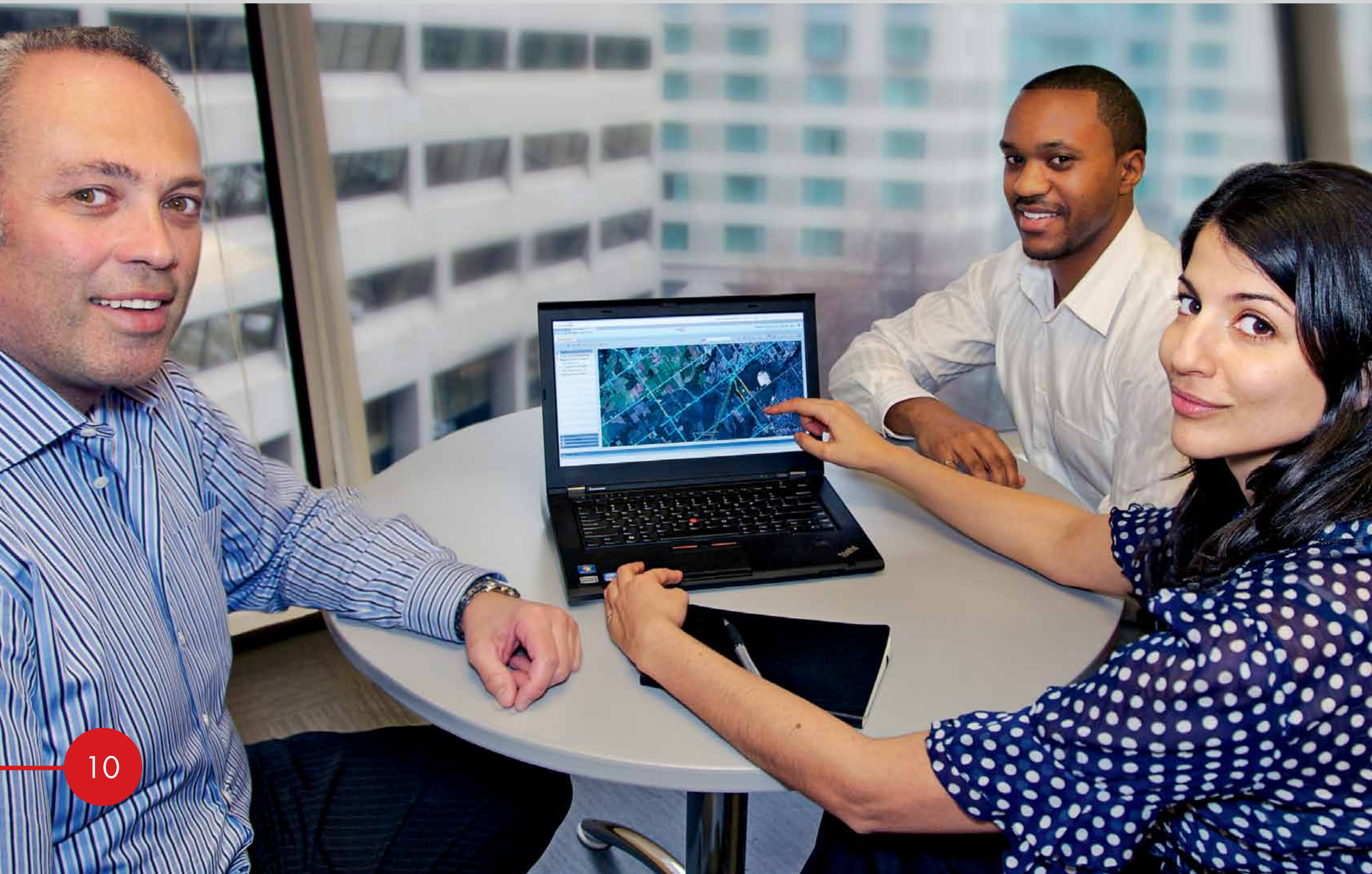
From our sustainment planning tool to our free mobile app, we are constantly looking for innovative and creative ways to better serve the electricity needs of Ontarians today, tomorrow and well into the future.

On December 22, 2013, at the peak of the ice storm, our free mobile app was downloaded 27,047 times.

The new Asset Analytics tool uses a combination of mapping, asset inventory and risk assessment to help make the best investment decisions and address the challenges planners and asset managers face when deciding what to replace and when to replace it.

### BY THE NUMBERS

- **1.7 million** distribution wood poles
- **500,000** pole top transformers
- **50,000** steel transmission structures
- **42,000** transmission wood pole structures
- **1,002** distribution stations
- **29,000** kilometres of transmission line conductor
- **1,400** transformers
- **1,200** distribution power transformers
- **285** transmission stations
- **123,000-** kilometre low-voltage distribution system



We own and operate Ontario's 29,000-kilometre high-voltage transmission network that delivers electricity to municipal utilities and large industrial customers, and a 123,000-kilometre low-voltage distribution system that serves approximately 1.3 million end-use customers.

Ontarians rely on us each and every day to provide them with the power they need to go about their daily lives. We are committed to providing safe, reliable and affordable electricity to the people of Ontario through the advancement of new technologies, programs and procedures.

## LAUNCH OF CUSTOMER INFORMATION SYSTEM

With a commitment to improving our customers' experiences and satisfying their needs, we launched our new Customer Information System (CIS) in May 2013.

The new system replaces an outdated, unsupported and unreliable system, and builds on our customer-first, customer-driven approach to providing value to our customers.

As is the case with any new system, the implementation of the CIS is part of a learning curve. Once it stabilizes, the benefits to our customers include improved call centre experiences, increased accuracy and timeliness of our billing system, and improved ability to address customers' concerns with up-to-date information.

## MOBILE APP

The popularity of our free mobile app grew in 2013. The app connects users to Hydro One's interactive online outage mapping system and allows them to receive detailed power outage information from anywhere in our service area.

Between January 1 and December 31, 2013, the app received 125,133 downloads, an average of 343 downloads per day. On December 22, 2013, at the peak of the ice storm, the app received 27,047 downloads.


## ASSET ANALYTICS

Asset Analytics is our sustainment planning tool created as a way for planners to manage and monitor assets in Hydro One's transmission and distribution systems. The first phase of Asset Analytics was launched in 2012 and work on the second phase began in 2013.

The Asset Analytics tool uses SAP data, Google Earth maps and sustainment planning information to map and list Hydro One's assets. It also has the ability to display risk information about their condition, which allows us to manage our assets so that we get the most out of them.

# COMMUNITY

## EVERY DAY COMMITMENT: ONE EMPLOYEE AT A TIME

We wouldn't be who we are without our employees. Hydro One is a diverse Company of like-minded and talented individuals who are committed to serving the people of Ontario. We are a Company where new ideas and original initiatives are fostered. We are dedicated, knowledgeable and reliable.

On March 23, 2013, during Earth Hour, Hydro One customers contributed to an overall reduction of 448 MW of energy consumption in the province. This demonstrated our commitment to educating our customers through programs and initiatives on ways to reduce energy consumption.

### ELECTRICITY DISCOVERY CENTRE

Our Electricity Discovery Centre (EDC) travels across Ontario, broadening Ontarians' understanding about electrical safety, energy conservation and how we invest in the province's electricity system.

- **In 2013, the EDC visited:**

1. The International Plowing Match
2. The Norfolk County Fair
3. The Royal Agricultural Winter Fair
4. Queen's Park
5. The Association of Municipalities of Ontario's Energy Connections Conference
6. Alight at Night

- **More than 10,000** visitors toured the EDC between September and December 2013.
- **More than 3,700** visitors toured the EDC during its launch at the International Plowing Match in Perth County between September 17 and 21, 2013.

- Internet connected
- Handicap accessible
- Solar smartphone charging station
- Electric vehicle charging station

Our success relies heavily on our people. From the crews in the field to those in head office, Hydro One employees represent many cultures, backgrounds and skills. We are as diverse as Ontario, and we work together to provide Ontarians with a level of customer service they so richly deserve.

Just as we are committed to investing in educating and training our current and future workforce, we are also committed to building our corporate reputation by investing in Ontario and its communities through the development of partnerships and initiatives.

A number of key partnerships and initiatives were launched in 2013 to continue Hydro One's culture of putting Ontarians first.

## ELECTRICITY DISCOVERY CENTRE

We broadened our longstanding commitment to electricity education and consumer engagement with the September 2013, launch of our Electricity Discovery Centre (EDC). The 1,000-square-foot, fully accessible mobile centre features hands-on exhibits about electrical safety, energy conservation and how we invest in Ontario's electricity system.

The EDC features a solar charging station, the Kids' Electricity Safety Team Headquarters, the Time-of-Use game and videos on Ontario's power system. The EDC travels across the province to engage and educate our customers.

The EDC visited a number of community fairs and events throughout Ontario in 2013, including the International Plowing Match in Mitchell in September, The Association of Municipalities Conference in Toronto in December, and Alight at Night in Morrisburg, also in December.

## WOMEN IN ENGINEERING UNIVERSITY PARTNERSHIP

In March, we announced a partnership with Ryerson University, the University of Ontario Institute of Technology, the University of Waterloo and Western University to increase the number of female students pursuing careers in the Science, Mathematics, Technology and Engineering fields.

The main goal of the Women in Engineering University Partnership is to increase the number of female engineering students and graduates over the next four years.

## LIGHTNING TRAIL RETREAT

In August, we partnered with Northern College and the District School Board Ontario North East to host a week-long retreat in Timmins for 29 Aboriginal youth between the ages of 12 and 18. As part of Hydro One's College Consortium, Lightning Trail provided the youth with opportunities to explore several trades and technology programs related to the electricity industry. Each student received a Certificate of Completion from Northern College, with three participants awarded Northern College Hydro One Aboriginal Leadership Entrance Bursaries.

## FIRST NATIONS, MÉTIS AND INUIT SCHOLARSHIP

In June, we held our second annual First Nations, Métis and Inuit awards ceremony in Toronto to recognize the achievements of First Nations and Métis youth in the energy sector. The award honours youth who are attending a post-secondary program with a focus on the electricity industry, and who have demonstrated that they are leaders in the communities we serve.

## WILLIAM PEYTON HUBBARD AWARD

Hydro One also sponsors two academic awards for outstanding black students attending an Ontario college or university through our William Peyton Hubbard Award.

# HYDRO ONE SENIOR MANAGEMENT

**Carmine Marcello**
President and
Chief Executive Officer,
Hydro One Inc.

**Joe Agostino**
General Counsel

**Laura Cooke**
Vice President,
Corporate Relations

**John Fraser**
Senior Vice President,
Internal Audit

**Peter Gregg**
Chief Operating Officer

**Judy McKellar**
Vice President,
People & Culture

**Rick Stevens**
Vice President,
Customer Service

**Sandy Struthers**
Chief Administration Officer
and Chief Financial Officer

# MANAGEMENT'S DISCUSSION AND ANALYSIS

**For the years ended December 31, 2013 and 2012**

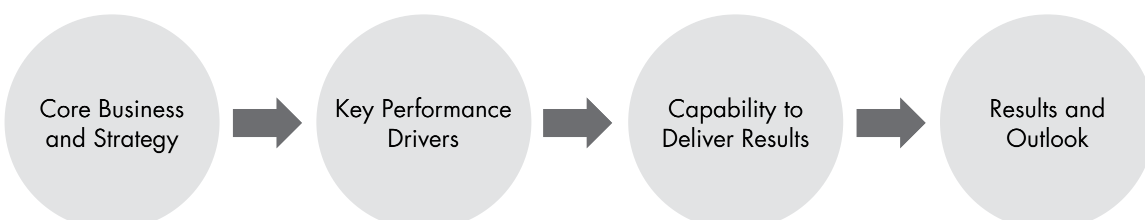
The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes (the Consolidated Financial Statements) of Hydro One Inc. (the Company) for the year ended December 31, 2013. 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 with reference to National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which are different from those of the US. This MD&A provides information for the year ended December 31, 2013.

## EXECUTIVE SUMMARY

We are wholly owned by the Province of Ontario (Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). Our mission and vision reflects the unique role we play in the economy of the Province and as a provider of critical infrastructure to all our customers. We strive to be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety; excellence; stewardship; and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial, transparent and which values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers. In 2013, we continued to focus on our core businesses and our commitment to our customers, and made important contributions to the rebuilding of Ontario's core infrastructure while continuing to meet the requirements of the *Green Energy Act* (GEA).

We manage our business using the following framework:




### *Core Business and Strategy*

Our corporate strategy is based on our mission and vision and our values. Our strategic objectives, which are discussed in the section "Our Strategy," encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; shareholder value; and productivity.

### *Key Performance Drivers*

Performance drivers have been identified that relate to achieving certain of our company's strategic objectives. We establish specific performance targets for each driver aimed at measuring the achievement of our strategic objectives over time. For example, we track the duration of unplanned customer interruptions per delivery point as an indication of our commitment to provide a reliable transmission system for our customers. We measure transmission and distribution unit costs as an indication of our commitment to increasing productivity. These and other key performance drivers are included in the discussion of our performance measures in the section "Performance Measures and Targets."

***Capability to Deliver Results***

We continue to use a balanced scorecard approach as we strive to manage our performance and deliver results each and every year. In 2013, we set nine stretch targets and we met or exceeded five of them. In 2012, we also met or exceeded five of nine stretch targets. We met our target for minimizing the duration of unplanned customer interruptions within our Distribution Business. We also met our targets of satisfying our transmission and distribution customers with the service they receive from our company. Our targets, and our 2013 performance relating to these targets, are discussed in the section "Performance Measures and Targets." Our ability to deliver results in each of our strategic areas is limited by risks inherent in our regulatory environment, our business, our workforce, and in the economic environment. These risks, as well as our strategies to mitigate them, are discussed in the section "Risk Management and Risk Factors."

***Results and Outlook***

During 2013, our financial fundamentals remained strong with net income of $803 million. In 2013, we issued $1,185 million of long-term debt, the proceeds of which were used to fund the retirement of $600 million of long-term debt, and to fund a portion of our capital expenditures and other corporate requirements. A full discussion of our results of operations and financing activities can be found in the sections "Annual Results of Operations" and "Liquidity and Capital Resources."

In 2013, we made capital investments totaling $1,394 million to improve our transmission and distribution systems' reliability and performance, address our aging power system infrastructure, facilitate new generation, and improve service to our customers. Capital investments for the next few years will include expenditures required to build critical infrastructure identified in the Long-Term Energy Plan (LTEP), which is based on recommendations from the Ontario Power Authority (OPA), and expenditures to address our aging power system infrastructure. Our future capital expenditures are more fully described in the section "Future Capital Investments."

## OVERVIEW
### Our Businesses

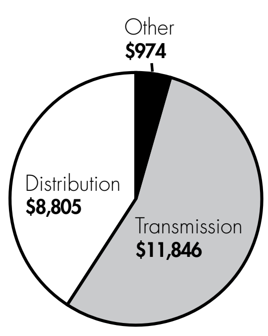
Our company has three reportable segments:

- Our Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- Our 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 our telecommunications business.

***Transmission***

Our Transmission Business includes the transmission business of our subsidiary Hydro One Networks, which owns and operates substantially all of Ontario's electricity transmission system. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2013, we earned total transmission revenues of $1,529 million, primarily by transmitting approximately 140.7 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and it is linked to five adjoining jurisdictions through 26 interconnections, through which we can accommodate electricity imports of up to 6,510 MW in the summer and 6,390 MW in the winter, and electricity exports of up to 6,070 MW in the summer and 6,270 MW in the winter. In terms of assets, our Transmission Business is our largest business segment, representing approximately 55% of our total assets at December 31, 2013.

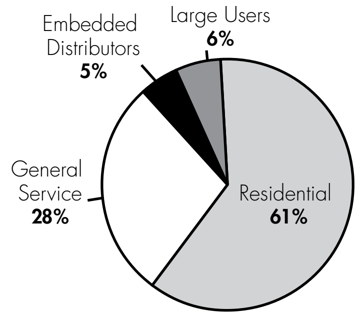
**Total Assets**
December 31, 2013
*(millions of Canadian dollars)*



***Distribution***

Our consolidated Distribution Business includes the distribution business of our subsidiary Hydro One Networks, as well as our subsidiaries Hydro One Brampton Networks Inc. (Hydro One Brampton Networks) and Hydro One Remote Communities Inc. (Hydro One Remote Communities). Our consolidated distribution system is the largest in Ontario and spans roughly 75% of the province. We serve approximately 1.4 million rural and urban customers. Hydro One Remote Communities operates small, regulated generation and distribution systems in a number of remote communities across northern Ontario that are not connected to Ontario's electricity grid. In 2013, we earned total distribution revenues of $4,484 million, and over half of our distribution revenues were earned from our residential customers. At December 31, 2013, our Distribution Business assets represented approximately 41% of our total assets.

**2013 Distribution Revenues**




***Other***

Our Other business segment primarily represents the operations of our subsidiary, Hydro One Telecom Inc. (Hydro One Telecom), which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario. In 2013, our Other business segment contributed revenues of $61 million, and had assets of $974 million at December 31, 2013, representing 4% of our total assets.

## Our Strategy

Our corporate strategy builds on our strong commitment to the Province and is shaped by our values. It lays out a set of objectives to position our company to achieve our mission and vision, which is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs.

- *Health and safety:* Nothing is more important than the health and safety of our employees, those who work on our property, and the public.
- *Excellence:* We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and affordable service, with integrity.
- *Stewardship:* We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.
- *Innovation:* We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that are inextricably linked. They drive the fulfillment of our mission and vision and ensure we remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our shareholder.

- *Creating an injury-free workplace and maintaining public safety.* Health and safety must be integrated into all that we do as we continue to reinforce that nothing is more important than the health and safety of our employees. We will continue to create a passion for preventing injury, staying safe and keeping each other safe. We will invest in building a culture of accountability to continue our drive to zero injuries in the workplace. In addition, we will continue to strengthen our already strong safety culture through our Journey to Zero initiative and our successful certification to the Occupational Health and Safety Assessment Series (OHSAS) 18001 standard.
- *Satisfying our customers.* We exist to serve our customers, and serving our customers means reducing costs, improving customer service and meeting their expectations regarding reliable power supply. We will continue to focus our efforts to improve our relationship with customers and to improve our customers' satisfaction with us. We will meet our commitments, make customers our focus in all planning discussions, communicate effectively, coordinate across our company, and maximize opportunities to improve our corporate image and every customer interaction. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs.

- *Continuous innovation.* Innovation represents one of our values and is critical to achieving our mission and vision. We have been using innovation and technology to build the foundation of our company as the utility of the future. Over the next two decades, we will continue to build on that foundation to improve the reliability and efficiency of our transmission and distribution systems and provide our customers with more capability to manage their power costs. The development of the Advanced Distribution System (ADS) is a key element in our investment in innovation, as are the investments we have made, through our Cornerstone project, in next generation business tools to enable us to implement leading industry practices and increase productivity.
- *Building and maintaining reliable, affordable transmission and distribution systems.* Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on continuing to meet the challenge of providing reliable, affordable service to our customers in a wide range of geographical regions and climate zones; incorporating ADS technology to provide greater visibility; and increased control and improved customer service. We will meet customer expectations regarding reliability, in part through our investment planning process, which starts with the identification of asset and customer needs.
- *Protecting and sustaining the environment for future generations.* Consistent with our value of stewardship, we play a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use.
- *Championing people and culture.* We believe our primary strength is the capability of our people. In order to sustain this advantage, we will continue to address the issues of corporate culture, labour demographics, diversity, development of critical core competencies, and skill and knowledge retention. We will continue to develop a culture of accountability and trust as a key component to fostering employee engagement. Our labour strategy is to consolidate and clarify our collective agreements, increase flexibility and reduce costs, and maintain a progressive relationship with our unions.
- *Maintaining a commercial culture that increases value for our shareholder.* For the delivery component of a customer bill, we are committed to maintaining total annual bill impacts for an average residential customer at or below the rate of inflation, and delivering income and dividends to our shareholder. We will pursue growth opportunities through local distribution company (LDC) consolidation to increase the enterprise value of our company by leveraging our existing assets, technologies, capabilities, unparalleled experience in LDC acquisitions and our distribution and transmission footprint.
- *Achieving productivity improvements and cost-effectiveness.* To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our shareholder.

## Performance Measures and Targets

We target and measure our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we maintain a focus on our strategic objectives and take mitigating actions as required. In 2013, we met or exceeded five of nine stretch targets. Overall, we are making progress towards achieving many of our strategic goals.

### *Achieving productivity improvements and cost-effectiveness*

One of our strategic objectives is to increase productivity through efficiency improvements and effective management of costs. The measures for this objective for 2013 were transmission unit cost and distribution unit cost. For transmission unit cost, we measured the capital expenditures and operation, maintenance and administration costs per dollar of gross in-service assets (expressed as a percentage). For distribution unit cost, the measure is capital expenditures and operation, maintenance and administration costs per kilometre of line ($'000/km) due to the length of line required to connect our rural customers. Our objective with our ongoing work and investment program is to maintain and improve our assets and monitor our productivity year-over-year. Our transmission unit cost target was set at 9.8%, and we met this target. The distribution unit cost target was set at $9,800 per kilometre of line. We did not meet this target.

### *Building and maintaining reliable, cost-effective transmission and distribution systems*

We continue to build and retain public confidence and trust in our operations, as stewards of Ontario's electricity grid. In 2013, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for customers in a safe, reliable and efficient fashion. We are conscious that commercial customers of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration when interruptions occur. Transmission and distribution reliability is measured through the duration of customer interruptions.

For the duration of unplanned customer interruptions within our transmission business, the target for 2013 was 9 minutes per delivery point. We did not meet this target.

For the duration of unplanned customer interruptions within our distribution business, the target for 2013 was set at 6.7 hours per customer. While we did not meet this target, our Board of Directors noted that the impact of storms in January and February of 2013 would require our company to change work practices and alter resource levels to simply meet the target and that the cost to do so would be prohibitive and not in the best interests of the ratepayer. Considering the storm impacts and the positive results over the balance of the year, our Board of Directors, in the exercise of its discretion, determined that this target was met.

***Satisfying our customers***

Customer satisfaction measures the degree to which our transmission and distribution customers are satisfied with the service they receive from our company. Customer satisfaction is based on the results of customer surveys conducted on our behalf by independent third parties. In 2013, for transmission customers we targeted a customer satisfaction rate of 82%. The survey was given to three major groups of transmission customers. Our Board of Directors determined that there was significant improvement in two of the three groups which comprise the survey members and accordingly, in the exercise of its discretion, considered this target met. For our distribution customers, we targeted a satisfaction rate of 86%, and we met this target.

***Employee engagement***

We continue to focus efforts on increasing employee engagement throughout the Company. An engaged workforce is one in which employees embrace the corporate values of safety, stewardship, excellence and innovation. The employee engagement survey is administered by an independent third party expert. Our goal is to improve the grand mean score year-over-year. The target of improving the grand mean score to 4.06 (out of 5) in 2013 was not met.

***Maintaining a commercial culture that increases value for our shareholder***

Achievement of strong financial performance is measured by a performance measure of targeted level of net income after tax. Our 2013 target was $702 million net income after tax, and we exceeded our target.

***Creating an injury-free workplace and maintaining public safety***

The safety of our employees is paramount. In 2013, we used medical attentions, defined as injuries that require treatment by a medical practitioner (beyond first aid), as the performance measure for this strategic objective. The medical attentions measure reflects incidents that are reported to the Workplace Safety Insurance Board and is calculated as the number of attentions per 200,000 hours worked. In 2013, we set a target of no higher than 1.9 attentions per 200,000 hours worked. We did not meet this target.

## REGULATION

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. Our transmission revenues primarily include our transmission tariff, which is based on the province-wide Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory accounts over specified timeframes.

The OEB 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.

### Renewed Regulatory Framework

In December 2010, the OEB initiated a coordinated consultation process for the development of a Renewed Regulatory Framework for Electricity. In October 2012, the OEB issued its report *A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach*. The report identified three rate-setting models available to provide choices suitable for distributors having varying capital requirements: a fourth generation Incentive Regulation Mechanism (IRM); a custom rate setting; and an Annual Incentive Rate-setting Index method. The report also provided information on performance measurement, continuous improvement and implementation of the new framework.

In late 2013, the OEB issued its *Report of the Board on Rate-Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. This report sets out the OEB's policies and approaches to the rate adjustment parameters for incentive rate setting for electricity distributors and the benchmarking of electricity distributor total cost performance. It also includes the OEB's determination on rate adjustment parameter values for 2014 incentive rate setting, which were used to adjust Hydro One Networks' 2014 distribution rates.

### Electricity Rates

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on both a two-tiered electricity pricing structure, with seasonal consumption thresholds, and a three-tiered electricity pricing structure with Time of Use (TOU) thresholds. Substantially all of our RPP customers are now on TOU billing. We received an exemption from the OEB, effective until December 31, 2014, from implementing mandatory TOU pricing for approximately 122,000 customers that are currently out of reach of our smart meter telecommunications infrastructure. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the OPA. RPP prices are reviewed by the OEB every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period.

Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators by the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998*. The IESO is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system. The following is a summary of the RPP for the reporting and comparative periods:

| RPP | Tier Threshold (kWh/month) | | Tier Rates (cents/kWh) | |
|---|---|---|---|---|
| **Effective Date** | **Residential** | **Non-Residential** | **Lower Tier** | **Upper Tier** |
| November 1, 2011 | 1,000 | 750 | 7.1 | 8.3 |
| May 1, 2012 | 600 | 750 | 7.5 | 8.8 |
| November 1, 2012 | 1,000 | 750 | 7.4 | 8.7 |
| May 1, 2013 | 600 | 750 | 7.8 | 9.1 |
| November 1, 2013 | 1,000 | 750 | 8.3 | 9.7 |

| RPP TOU | Rates (cents/kWh) | | |
|---|---|---|---|
| **Effective Date** | **On Peak** | **Mid Peak** | **Off Peak** |
| November 1, 2011 | 10.8 | 9.2 | 6.2 |
| May 1, 2012 | 11.7 | 10.0 | 6.5 |
| November 1, 2012 | 11.8 | 9.9 | 6.3 |
| May 1, 2013 | 12.4 | 10.4 | 6.7 |
| November 1, 2013 | 12.9 | 10.9 | 7.2 |

#### *Transmission Rates*

In May 2010, we filed a cost-of-service application with the OEB for 2011 and 2012 transmission rates, seeking the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012. In December 2010, the OEB approved revenue requirements of $1,346 million for 2011 and $1,658 million for 2012. The approved 2012 revenue requirement was higher than that applied for, reflecting OEB direction for our company to adopt a cost capitalization policy based on modified IFRS. This adjustment was subsequently reversed when the OEB approved the use of US GAAP for transmission rate-setting purposes beginning January 1, 2012. Consequently, the OEB approved a revenue requirement of $1,418 million for 2012, along with new 2012 UTRs, with an effective date of January 1, 2012. The new rates resulted in an approximate 8% transmission rate increase, or 0.6% when considering total bill impact, for a typical residential customer consuming 800 kWh per month. The adoption of US GAAP in lieu of modified IFRS as a basis for rate setting decreased the approved rates by approximately 15%.

In May 2012, we filed a cost-of-service application with the OEB for our 2013 and 2014 transmission rates. The application sought OEB approval for revenue requirement increases of approximately 0.6% in 2013 and 9.1% in 2014, or estimated increases of 0% in 2013 and 0.7% in 2014 on an average customer's total bill. In November 2012, we submitted a draft Rate Order, which included revenue requirements of approximately $1,438 million and $1,528 million for 2013 and 2014, respectively. For the transmission portion of the bill, this represents no change from existing 2012 OEB-approved rate levels in 2013 and a 5.8% increase in 2014. For a typical residential customer consuming 800 kWh per month, this represents increases of nil for 2013 and 0.5% for 2014. In December 2012, the OEB approved the 2013 and 2014 transmission revenue requirements of $1,438 million and $1,528 million, respectively, and the 2013 Ontario UTRs, which remained unchanged at the 2012 levels.

On December 6, 2013, we submitted a draft Rate Order for our 2014 transmission rates. The 2014 revenue requirement has been 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. For the transmission portion of a customer's bill, this represents an increase of 6.3% in 2014, or 0.5% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

***Distribution Rates***

As a distributor, we are responsible for delivering electricity and billing our customers for our approved distribution rates, purchased power costs and other approved regulatory charges. Substantially all of our purchased power costs and other approved regulatory charges are settled through the IESO, which facilitates payments to other parties, such as generators, the Ontario Electricity Financial Corporation (OEFC), and itself.

- **Hydro One Networks**

  Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for 2011, with a revenue requirement of $1,218 million.

  In June 2012, Hydro One Networks filed an IRM rate application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued a final Rate Order, 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.

  On April 26, 2013, Hydro One Networks filed an IRM rate application with the OEB for 2014 distribution rates, to be effective January 1, 2014. On September 26, 2013, the OEB issued a partial decision, approving a rate rider to recover a 2014 revenue requirement of $29.3 million for operation, maintenance and administration expenses and in-service capital costs of the ADS Project, which will modernize our distribution system. On December 5, 2013, the OEB issued its final decision, which resulted in an increase of 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.

  On December 19, 2013, Hydro One Networks filed a 2015–2019 distribution custom rate application with the OEB, for rates effective January 1 of each test year. This application is a five-year custom rate application which is being submitted under the OEB's Renewed Regulatory Framework for Electricity Distributors. It has been customized to fit Hydro One Networks' specific circumstances, which necessitate significant multi-year investments. The submitted evidence includes the overall business plan, revenue requirements, and rate information necessary to support the issuance of a notice by the OEB. We are seeking OEB approvals for revenue requirements of $1,411 million for 2015, $1,515 million for 2016, $1,571 million for 2017, $1,615 million for 2018, and $1,666 million for 2019. If the application is approved as filed, the resulting change to the distribution portion of the average customer bill will be approximately a 1.3% decrease in 2015, 4.2% increase in 2016, 2.6% increase in 2017, 1.9% increase in 2018, and 2.9% increase in 2019, for a typical residential customer consuming 800 kWh per month. When considering total bill impact, the resulting change will be approximately a 1.1% decrease in 2015, 1.5% increase in 2016, 0.9% increase in 2017, 0.7% increase in 2018, and 1.1% increase in 2019.

- **Hydro One Brampton Networks**

  In September 2011, Hydro One Brampton Networks filed an IRM application with the OEB for 2012 distribution rates, with an effective date of January 1, 2012. In January 2012, the OEB released a decision that resulted in a reduction in distribution rates of approximately 13.2% for 2012, or a 1.7% reduction on the average customer's total bill, for a typical residential customer consuming 800 kWh per month. 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, to be effective January 1, 2013. In December 2012, the OEB released a decision that resulted in an increase in distribution rates of approximately 0.3% for 2013, or less than 0.1% on the average customer's total bill, 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. On December 5, 2013, the OEB released a decision that resulted in a reduction in distribution rates of approximately 2.5% for 2014, or a 0.5% reduction on the average customer's total bill, for a typical residential customer consuming 800 kWh per month.

- **Hydro One Remote Communities**

  In November 2011, Hydro One Remote Communities filed an IRM application with the OEB for 2012 distribution rates. In March 2012, the OEB approved an increase of approximately 1.08% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2012, representing an increase of approximately $1 on the average residential customer's total bill.

  In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 distribution rates, seeking approval for a 2013 revenue requirement of $53 million. In August 2013, the OEB issued a final decision approving a revenue requirement of $51 million and rate increase of approximately 3.45%, with an effective date of May 1, 2013.

  In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 distribution, seeking approval for a rate increase of approximately 0.48%, to be effective May 1, 2014.

## Recent Industry Developments

### *Long-Term Energy Plan*

In 2010, the Ministry of Energy released Ontario's LTEP, which set out the province's expected electricity needs until 2030 and supported the continued procurement of new, cleaner generation. The 2010 LTEP addressed seven key areas: demand, supply, conservation, transmission, Aboriginal communities, capital investments, and electricity prices.

On December 2, 2013, the Province released its updated LTEP, *Achieving Balance*, which sets out the Province's plan of action for the energy sector, including strategies for mitigating increases in electricity rates; increased renewable energy procurement; nuclear refurbishment; enhanced regional planning with respect to energy infrastructure; transmission enhancements; encouraging Aboriginal participation in energy development, transmission and conservation projects; and the expansion of natural gas infrastructure. The plans are guided by the goal of balancing five core principles: cost-effectiveness, reliability, clean energy, community engagement, and conservation and demand management (CDM). Pursuant to the updated LTEP, the Province "will encourage Ontario Power Generation Inc. (OPG) and Hydro One to explore new business lines and opportunities inside and outside Ontario. These opportunities will help leverage existing areas of expertise and grow revenues for the benefit of Ontarians." We will continue to work with the Province to develop business plans and efficiency targets that will reduce costs and result in significant ratepayer savings.

In November 2013, the Minister of Energy issued a directive to the OEB, which in turn issued a decision and order on January 9, 2014, to amend the transmission licence of Hydro One Networks to develop and seek approval for the Northwest Bulk Transmission Line Project, an expansion or reinforcement of the transmission system in the area west of Thunder Bay. The scope and timing of the Northwest Bulk Transmission Line Project shall be in accordance with the recommendations of the OPA.

***Distribution Sector Consolidation***

In April 2012, the Province announced it was launching a comprehensive review of Ontario's electricity sector to explore options to improve efficiencies, including LDC consolidation. As a result, the Province created the Ontario Distribution Sector Review Panel (Panel). In December 2012, the Panel released its report, "Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First" with recommendations for electricity sector consolidation. This report recommended that the 73 LDCs, comprising the focus of the report, be consolidated into eight to 12 larger regional electricity distributors within a two-year timeframe. Specifically, it recommended there be two regional distributors in northern Ontario and between six and ten regional distributors in southern Ontario with a minimum of 400,000 customers each. Given our company's position as the largest LDC, the report recommended that Hydro One Networks be given unambiguous direction to lead and engage in the discussion of the merger of distribution assets with the appropriate interested utilities on a commercial basis. The Minister of Energy subsequently indicated he was supportive of voluntary consolidation and expects all LDCs to pursue innovative partnerships and transformative initiatives that will result in electricity ratepayer savings.

On April 2, 2013, we reached an agreement with Norfolk County to acquire the outstanding shares of Norfolk Power Inc. (Norfolk Power) for $93 million, subject to final closing adjustments. We will pay Norfolk County approximately $66 million net after assuming Norfolk Power's existing debt of approximately $27 million. Norfolk Power is a holding company that owns Norfolk Power Distribution Inc., a local distribution company, and Norfolk Energy Inc., a non-rate regulated energy services company. The selection of our company as successful bidder followed a comprehensive competitive sales process initiated by Norfolk Power. The acquisition is pending a regulatory decision from the OEB, which is anticipated in 2014.

We will continue to pursue growth opportunities through LDC consolidation by leveraging our existing assets, technologies, capabilities, unparalleled experience in LDC acquisitions, and our distribution footprint.

***Procurement of New Generation***

In 2009, the OPA launched its Feed-in Tariff (FIT) Program which is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy, and waterpower up to 50 MW. The FIT program is currently divided into three streams: Micro FIT (projects up to 10 kW), Small FIT (projects between 10 kW and 500 kW) and regular FIT (projects greater than 500 kW), all of which may result in connections to our distribution system. Under the FIT program, the OPA has entered into contracts or conditional contracts with generation proponents pursuant to which the OPA will pay a fixed rate for power produced over a specified period of time. We continue to connect projects for which there are firm contracts.

On May 30, 2013, the Province announced that it would make 900 MW of new capacity available between 2013 and 2018 for the Small FIT and Micro FIT programs. The Province has set annual procurement targets, from 2014 onwards, of 150 MW for Small FIT generation and 50 MW for Micro FIT generation. The Province is working with the OPA to develop a competitive process for renewable energy generation projects above 500 kW. The new process will replace the existing large project stream of the FIT program. As at December 31, 2013, our company has connected more than 370 FIT and 11,000 Micro FIT projects.

***Conservation and Demand Management***

In April 2012, the OEB issued its CDM guidelines for all electricity distributors. These guidelines provide guidance on certain provisions in the CDM Code and the type of evidence that should be filed by distributors in support of an application for OEB-approved CDM programs. The guidelines also provide details on the Lost Revenue Adjustment Mechanism (LRAM) related to CDM programs implemented under the CDM Code. LRAM is the mechanism by which LDCs are compensated for lost revenues associated with their respective load reductions resulting from CDM programs. In addition, the guidelines state that savings associated with TOU pricing are eligible to be counted towards the 2011–2014 CDM targets.

In December 2012, the Minister of Energy issued a directive to the OPA to extend funding for the OPA-contracted Ontario-wide CDM programs for one additional year, to December 31, 2015. This extension will provide an opportunity for the OPA and LDCs to collaboratively work to strengthen the current framework, and to keep customer programs in place for 2015.

On September 30, 2013, in accordance with the CDM Code, Hydro One Networks and Hydro One Brampton Networks each filed a 2012 Annual CDM Report with the OEB. The reports discussed CDM activities, energy and peak demand savings results achieved in 2012, and plans to reach CDM targets by the end of 2014. Hydro One Networks reported that it expects to reach 100% of its demand target and 80% of its cumulative energy target by 2014. Hydro One Brampton Networks reported that it expects to reach 68% of its demand target and 100% of its cumulative energy target by 2014. The OEB has indicated that there are several LDCs that have a similar issue. The OEB is aware of our situation.

## ANNUAL RESULTS OF OPERATIONS

| Year ended December 31 *(millions of Canadian dollars)* | **2013** | 2012 | $ Change | % Change |
|---|---|---|---|---|
| Revenues | **6,074** | 5,728 | 346 | 6 |
| Purchased power | **3,020** | 2,774 | 246 | 9 |
| Operation, maintenance and administration | **1,106** | 1,071 | 35 | 3 |
| Depreciation and amortization | **676** | 659 | 17 | 3 |
| | **4,802** | 4,504 | 298 | 7 |
| **Income before financing charges and provision for payments in lieu of corporate income taxes** | **1,272** | 1,224 | 48 | 4 |
| Financing charges | **360** | 358 | 2 | 1 |
| **Income before provision for payments in lieu of corporate income taxes** | **912** | 866 | 46 | 5 |
| Provision for payments in lieu of corporate income taxes | **109** | 121 | (12) | (10) |
| **Net income** | **803** | 745 | 58 | 8 |

### Revenues

| Year ended December 31 *(millions of Canadian dollars)* | **2013** | 2012 | $ Change | % Change |
|---|---|---|---|---|
| Transmission | **1,529** | 1,482 | 47 | 3 |
| Distribution | **4,484** | 4,184 | 300 | 7 |
| Other | **61** | 62 | (1) | (2) |
| | **6,074** | 5,728 | 346 | 6 |
| Average annual Ontario 60-minute peak demand (MW)[1] | **21,493** | 21,132 | 361 | 2 |
| Distribution – units distributed to customers (TWh)[1] | **29.8** | 29.2 | 0.6 | 2 |

[1] System-related statistics are preliminary.

### *Transmission*

Transmission revenues primarily consist of our transmission tariff, which is based on the monthly peak electricity demand across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets, ancillary revenues primarily attributable to maintenance services provided to generators, and secondary use of our land rights.

Our 2013 transmission revenues were higher by $47 million, or 3%, compared to 2012. The average Ontario 60-minute peak demand was higher in 2013, resulting in an increase in transmission revenues of $26 million, compared to 2012. The higher energy consumption in 2013 mainly resulted from a warmer summer and a colder winter, as compared to 2012. In addition, we experienced higher revenues of $21 million in 2013, associated with the OEB's approval of export service revenues and ancillary services.

***Distribution***

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our Distribution Business. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include minor ancillary distribution service revenues, such as fees related to the joint use of our distribution poles by the telecommunications and cable television industries, as well as miscellaneous charges such as charges for late payments.

Our 2013 distribution revenues were higher by $300 million, or 7%, compared to 2012. The increase was primarily due to the recovery of higher purchased power costs of $246 million, as described below under "Purchased Power." In addition, energy consumption was higher by $29 million in 2013, mainly resulting from a warmer summer and a colder winter, as compared to 2012. Distribution revenues also increased by $15 million as a result of our placement in service of new smart grid and smart meter investments, which are currently being recovered through separate rate mechanisms.

In December 2012, the OEB approved new tariff rates effective January 1, 2013, based on its third generation IRM process. As part of the IRM decision, the OEB approved our application for an additional rate rider related to an incremental capital module (ICM) adjustment to our rates, reflecting our placement in service of certain specific capital investments. This ICM approval resulted in an increase of $13 million, compared to 2012. In addition, the OEB's IRM decision resulted in higher distribution revenues of $10 million, which will support the maintenance and investment requirements of our distribution system and enable the safe and reliable delivery of electricity to our customers throughout Ontario. The 2013 distribution revenue increases were partially offset by lower 2013 ancillary distribution revenues of $13 million, primarily associated with OEB-approved regulatory accounts.

## Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of purchased electricity delivered to customers within our distribution service territory. These costs comprise the wholesale commodity cost of energy, the IESO wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy is based on the OEB's RPP, as described above under "Regulation."

Our 2013 purchased power costs increased by $246 million, or 9%, to $3,020 million, compared to 2012. The increase in our 2013 purchased power costs was mainly due to a $104 million increase resulting from higher purchased power costs for customers who are not eligible for the RPP, an $85 million increase resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers, a $44 million increase due to higher electricity demand, a $9 million increase resulting from the IESO's Smart Metering Entity charge effective May 1, 2013, and a $4 million reduction in wholesale market service charges levied by the IESO.

## Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, materials, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof related to our transmission and distribution lines, stations and buildings. Our transmission operation, maintenance and administration costs are incurred to sustain our high-voltage transmission stations, lines and rights-of-way. Our distribution operation, maintenance and administration costs are required to maintain our low-voltage distribution system. Our company continues to focus on managing its costs, while continuing to substantially complete our planned work programs for both our Transmission and Distribution Businesses.

| Year ended December 31 *(millions of Canadian dollars)* | **2013** | 2012 | $ Change | % Change |
|---|---|---|---|---|
| Transmission | **375** | 402 | (27) | (7) |
| Distribution | **672** | 608 | 64 | 11 |
| Other | **59** | 61 | (2) | (3) |
| | **1,106** | 1,071 | 35 | 3 |

***Transmission***

Our 2013 transmission operation, maintenance and administration costs decreased by $27 million, or 7%, to $375 million, compared to 2012. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system.

Expenditures in support of our transmission system decreased by $33 million in 2013, compared to 2012, primarily due to a reduction to our provision for payments in lieu of property taxes related to transmission stations for the years 1999 to 2012, inclusive, following the finalization of the related regulations and receipt of a final assessment of our property tax returns. The decrease in our transmission system support costs was partially offset by an increase of $6 million in our work program costs, compared to 2012. This increase was primarily due to higher expenditures related to our forestry work program on our transmission rights-of-way resulting from heavy tree densities, power equipment preventive and corrective maintenance, and emergency restoration requirements as a result of severe flooding at our Richview and Manby transmission stations caused by a major rainstorm in July 2013. We also experienced increased cyber security and internal compliance program requirements related to the reliability standards and criteria mandated by the North American Electric Reliability Corporation (NERC). These increases in work program costs were partially offset by lower expenditures related to the OPA's recommendation to increase short circuit and/or transformer capacity at ten of our transmission stations to enable the connection of small renewable projects, as this work was substantially completed by the end of 2012. Expenditures for these station upgrades were recorded within operation, maintenance and administration rather than as capital expenditures, given that recovery was restricted pursuant to a shareholder declaration made in April 2011. No such declarations were issued in 2013. In addition, we experienced lower expenditures within our overhead lines program.

***Distribution***

Our 2013 distribution operation, maintenance and administration costs increased by $64 million, or 11%, to $672 million, compared to 2012. Our work program expenditures increased by $63 million compared to 2012, mainly as a result of increased power restoration expenditures following major storms in 2013, increased customer-driven work related to trouble calls and cable locates in support of the new One Call Program, higher requirements within the line patrol program, higher expenditures on our customer care programs, higher Information Technology (IT) improvements and enhancements, and continued work on the ADS Project. These impacts were partially offset by lower station corrective and preventive maintenance expenditures, as well as lower line clearing expenditures, compared to 2012. Our expenditures in support of our distribution system increased marginally by $1 million, compared to 2012.

## Depreciation and Amortization

Our 2013 depreciation and amortization costs increased by $17 million, or 3%, compared to 2012. This increase was attributable to higher 2013 depreciation expense, primarily related to our placement of new assets in service consistent with our ongoing capital work program, as well as higher asset removal costs in 2013.

## Financing Charges

Financing charges increased by $2 million, or 1%, to $360 million for 2013, compared to 2012. Higher financing costs in 2013 were mainly due to a decrease in interest capitalized, partially offset by a decrease in interest expense on long-term debt due to lower average interest rates.

## Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) decreased by $12 million, or 10%, to $109 million in 2013, compared to 2012. This decrease primarily resulted from changes in net temporary differences, and a true-up relating to the 2012 research and development tax credits. This reduction was partially offset by the impact of higher levels of pre-tax income in 2013, compared to 2012.

## Net Income

Our 2013 net income increased by $58 million, or 8%, to $803 million, compared to 2012. We experienced higher distribution revenues in 2013 mainly reflecting increased purchased power costs, primarily related to the OEB's RPP rate-setting process and the IESO's spot market. We also experienced increased transmission revenues in 2013 reflecting a higher peak demand due to intermittent periods of hot weather in the summer of 2013, as well as extreme cold winter weather. Our 2013 net income was also positively impacted by a lower provision for PILs and by a reduction to our provision for payments in lieu of transmission station property taxes, following the finalization of the assessment of certain prior years' property tax returns. This reduction was partially offset by power restoration expenditures following several major storms in 2013.

## QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2012 through December 31, 2013. This information has been derived from our unaudited interim Consolidated Financial Statements and our audited annual Consolidated Financial Statements which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

| *(millions of Canadian dollars)* | **2013** | | | | 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| *Quarter ended* | **Dec. 31** | **Sept. 30** | **Jun. 30** | **Mar. 31** | Dec. 31 | Sept. 30 | Jun. 30 | Mar. 31 |
| Total revenue | **1,557** | **1,542** | **1,403** | **1,572** | 1,435 | 1,466 | 1,359 | 1,468 |
| Net income | **160** | **218** | **168** | **257** | 165 | 201 | 169 | 210 |
| Net income to common shareholder | **155** | **214** | **163** | **253** | 160 | 197 | 164 | 206 |

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

## LIQUIDITY AND CAPITAL RESOURCES

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

### Summary of Sources and Uses of Cash

| Year ended December 31 *(millions of Canadian dollars)* | **2013** | 2012 |
|---|---|---|
| **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) |
| **Investing activities** | | |
| Capital expenditures | **(1,412)** | (1,463) |
| **Other financing and investing activities** | **11** | 21 |
| **Net change in cash and cash equivalents** | **370** | (33) |

### Operating Activities

Net cash from operating activities increased by $110 million to $1,404 million in 2013, compared to 2012. The increase was primarily due to higher 2013 net income, compared to 2012, as well as changes in accrual balances, mainly related to timing of tax payments and to capital projects. The increase was partially offset by growth in accounts receivable balances, resulting from higher revenues and lower collections in the period.

### Financing Activities

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

Our Commercial Paper Program is supported by our $1,500 million committed revolving credit facility with a syndicate of banks, which matures in June 2018. In addition, our investment in Province of Ontario Floating-Rate Notes of $250 million (with a fair value of $251 million at December 31, 2013) maturing on November 19, 2014 also provides temporary liquidity. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

At December 31, 2013, we had $9,045 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2014 and 2062. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. At December 31, 2013, $1,815 million remained available until October 2015.

Cash generated from operations, after payment of expected dividends, will not be sufficient to fund capital expenditures, fund the repayment of our existing indebtedness, and meet other liquidity requirements. We rely on debt financing through our MTN Program and our Commercial Paper Program to repay our existing indebtedness and fund a portion of our capital expenditures.

The credit ratings assigned to our debt securities by external rating agencies are important to our ability to raise capital and funding to support our business operations. Maintaining strong credit ratings allows us to access capital markets on competitive terms. A material downgrade of our credit ratings would likely increase our cost of funding significantly, and our ability to access funding and capital through the capital markets could be reduced. Our corporate credit ratings from approved rating organizations are as follows:

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

[1] On April 25, 2012, S&P revised their outlook on our company to negative from stable.

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets, and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that third party debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We were in compliance with all these covenants and limitations as at December 31, 2013.

In 2013, we issued $1,185 million of long-term debt under our MTN Program, compared to $1,085 million of long-term debt issued in 2012. In 2013, we also repaid $600 million in maturing long-term debt, compared to $600 million of long-term debt called and redeemed in 2012, prior to its maturity date of November 15, 2012. We had no short-term notes outstanding at December 31, 2013 or 2012.

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

In 2013, we paid dividends to the Province in the amount of $218 million, consisting of $200 million in common dividends and $18 million in preferred dividends. In 2012, we paid dividends to the Province in the amount of $370 million, consisting of $352 million in common dividends and $18 million in preferred dividends. In 2013, cash dividends per common share were $2,000, compared to $3,523 per common share in 2012. Cash dividends per preferred share were $1.375 in each of 2013 and 2012.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns to our shareholder.

## Investing Activities

Capital investments consist of cash capital expenditures and related accruals. Capital investments primarily relate to enhancing and reinforcing of our transmission and distribution infrastructure.

| Year ended December 31 *(millions of Canadian dollars)* | **2013** | 2012 | $ Change | % Change |
|---|---|---|---|---|
| Transmission | **714** | 776 | (62) | (8) |
| Distribution | **673** | 671 | 2 | – |
| Other | **7** | 7 | – | – |
| **Total capital investments** | **1,394** | 1,454 | (60) | (4) |

### *Transmission*

Our 2013 transmission capital investments decreased by $62 million, or 8%, to $714 million, compared to 2012. Investments to expand and reinforce our transmission system were $170 million in 2013, representing a decrease of $143 million, compared to 2012. The decrease was mainly due to the completion of our Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. This project was placed in-service in May 2012. In addition, we experienced lower expenditures as a result of completing our Commerce Way Transmission Station, a new load supply station in the City of Woodstock to address load growth issues in the Woodstock area, and the Switchyard Reconstruction Project at our Burlington Transmission Station, where two new 115 kV switchyards were constructed to increase the load supply capacity and to ensure reliability of supply to customers in the area. These projects were placed in-service in February 2013 and December 2012, respectively.

During 2013, we continued to invest in inter-area network projects to support the Province's supply mix objectives for generation, and in load customer connections and local area supply projects to address growing loads. Our local area supply project expenditures include investments in our Midtown Transmission Reinforcement Project, which will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west. Work at our Hearn Switching Station was partially completed in December 2013, where we rebuilt an existing switchyard that had reached its end-of-life. This project will also increase short circuit capability to accommodate future connection of renewable generation in central and downtown Toronto. We are also constructing our Lambton to Longwood Transmission Upgrade to increase transmission capability between our Lambton (Sarnia) and Longwood (London) transmission stations. This project is needed to satisfy government policy relating to the incorporation of 10,700 MW of non-hydroelectric renewable generation resources by 2021.

Investments to sustain our existing transmission system were $481 million in 2013, representing an increase of $89 million, compared to 2012. In 2013, we made significant investments in the refurbishment and replacement of end-of-life equipment for overhead lines and system re-investments in order to improve reliability, as well as replacement of circuit breakers. In addition, we have experienced higher expenditures associated with the timing of work related to the replacement of end-of-life power transformers. We continued work on replacing end-of-life underground transmission cables between our Strachan Transmission Station and Riverside Junction. These new underground cables will maintain a reliable supply of electricity to downtown Toronto. These increases were partially offset by lower expenditures related to the replacement of protection and control equipment.

Our other transmission capital investments were $63 million in 2013, representing a decrease of $8 million, compared to 2012. The decrease was mainly due to lower requirements associated with IT initiatives, including our entity-wide SAP information system replacement and improvement project, and timing of field facilities improvements. These reductions were partially offset by increased fleet acquisitions and emergency flood restoration work at our Richview transmission station caused by a major rainstorm in July 2013.

***Distribution***

Our 2013 distribution capital investments increased by $2 million, or less than 1%, to $673 million, compared to 2012. Investments to expand and reinforce our distribution network were $235 million in 2013, representing a decrease of $49 million, compared to 2012. We experienced reduced expenditures related to some of our major projects, including the ADS Project, as we completed the deployment of our Distribution Management System within our Owen Sound pilot area in 2012, and the Smart Metering Project, as most of the network expansion work was completed in 2012. In 2013, we also experienced a lower demand for new customer connections and upgrades. These decreases were partially offset by increased work on upgrading and adding capacity to our system to enable new customer connections and timing of generation connection projects. Given that the OEB has assessed the prudency of the ADS Project, the next phase of this project is anticipated in 2014.

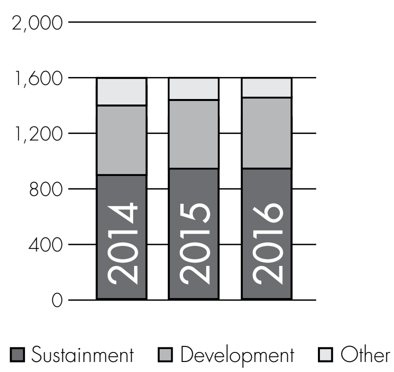
Investments to sustain our distribution system were $324 million in 2013, representing an increase of $79 million, compared to 2012. The increase was primarily due to increased expenditures for replacements related to storm restoration work caused by major storms in 2013. We also experienced increased work within our wood pole replacement program and station refurbishment projects. Investments were also impacted by the timing of customer contribution payments received in 2012 relating to work for joint use and relocation of our lines. These increases were partially offset by lower work within our lines programs.

Our other distribution capital investments were $114 million in 2013, representing a decrease of $28 million, compared to 2012. The majority of these expenditures were related to the Customer Information System (CIS) phase of our entity-wide information system replacement and improvement project, which was placed into service in May 2013. In addition to replacing end-of-life systems, this implementation will result in process improvements that are expected to provide many benefits including enhancements to customer satisfaction through reduced call times and first call resolution of issues given faster availability of information. Productivity savings are also anticipated to result from performance improvements, consolidation and/or decommissioning of legacy IT systems. In addition, we experienced decreased expenditures associated with IT initiatives, including our entity-wide SAP information system replacement and improvement project, and the timing of field facilities improvements, partially offset by an increase in fleet acquisitions and emergency flood restoration work at our Richview Transmission Station.

## Future Capital Investments

Our capital investments for 2014 are budgeted at approximately $1,600 million. Our 2014 capital budgets for our Transmission and Distribution Businesses are approximately $950 million and $650 million, respectively. Consolidated capital investments are expected to be approximately $1,600 million in each of 2015 and 2016. These investment levels reflect the sustainment requirements of our aging infrastructure. Our sustainment program capital investments are expected to be approximately $900 million in each of 2014, 2015, and 2016. Our development capital investments are expected to be approximately $450 million in 2014, $500 million in 2015, and $500 million in 2016. Our development projects include the inter-area network upgrades that reflect supply mix policies, local area supply improvements, the ADS, new load and generation connections and requirements to enable Distributed Generation (DG), and customer demand work. Other capital investments are expected to be $250 million in 2014, $200 million in 2015, and $200 million in 2016. This includes investments in operating infrastructure integration, IT, fleet services and facilities, and real estate. Our future capital investments amounts do not include future LDC acquisitions.

**Future Capital Investments**
*(millions of Canadian dollars)*




***Transmission***

Transmission capital investments are incurred to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. Our sustainment program future capital investments include the replacement of air blast circuit breakers and switchgear, high-voltage underground cables, and power transformers. These investments are necessary to ensure that we maintain our current levels of supply to our customers and continue to meet all regulatory, compliance, safety and environmental objectives.

Our development future capital investments include the Clarington Transmission Station Project to install additional auto-transformer capacity in east Greater Toronto Area; the Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in south-central Guelph; investments in ADS; requirements to enable DG; and up to four other transmission station upgrades, which when combined with the new Hearn Switching Station, will collectively enable up to 600 MW of new generation capacity in the Niagara, Toronto and Ottawa areas.

In 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transmission stations. Seven of these station upgrades have now been completed, and alternate solutions have been determined for the remaining three projects. The Lambton to Longwood Transmission Upgrade has a required in-service date of December 2014, and is included in our budgeted future capital investments. This project is needed to satisfy government policy relating to the incorporation of 10,700 MW of non-hydroelectric renewable generation resources by 2021. In August 2013, the OPA requested us to terminate work related to the Southwestern Ontario Reactive Compensation Priority Project, and an OPA recommendation regarding the third priority specified transmission project, which was not included in the most recent LTEP, is not expected in the foreseeable future. Therefore, these two projects are not included in our budgeted future capital investments.

Based on the OEB's framework for competitive designation for the development of eligible transmission projects, we did not include in our budgeted future capital investments any projects that could meet the definition of expansions. We do not plan to undertake large capital investments without a reasonable expectation of recovering them through our rates.

The actual timing and investments of many development projects are uncertain as they are dependent upon various regulatory approvals, negotiations with customers, neighbouring utilities and other stakeholders, and consultations with First Nations and Métis communities. Projects are also dependent upon the timing and level of generator contributions for enabling facilities.

***Distribution***

Distribution capital investments include the sustainment of our infrastructure. Our core work will continue to focus on maintaining the performance of our aging distribution asset base through renewal and refurbishment activities. Planned capital investments include the continued replacements of equipment and components that are beyond their expected service life, as well as increased wood pole replacements and distribution station refurbishments. Sustainment capital investments in the Smart Metering project will decrease through 2016.

Distribution development capital investments are expected to be relatively stable through 2016, with the exception of capital contributions for capacity improvements at the Orleans Transmission Station in 2015 and the Hanmer Transmission Station in 2016. We will continue to make investments required to connect new load and DG customers, as well as investments to ensure the system is capable of supplying customer needs. During 2014 to 2016, a number of our projects will address local load growth issues. Generation connection investments will decrease as the volume of connections is expected to decrease. The budgeted capital expenditures only reflect projects with FIT and Micro FIT Program contracts from the OPA that are expected to connect to our distribution system.

In 2014 and 2015, the ADS Project will continue to pilot various technologies and related capital investments will begin to decrease in 2016. Pilot technologies include improvements to outage response management through more effective resource dispatch, automation to isolate faults where needed, and the dynamic regulation of voltage to reduce losses.

## 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 our 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 our debt and other major contractual obligations, as well as other major commercial commitments:

| December 31, 2013 *(millions of Canadian dollars)* | Total | 2014 | 2015/2016 | 2017/2018 | After 2018 |
|---|---|---|---|---|---|
| **Contractual obligations** *(due by year)* | | | | | |
| Long-term debt – principal repayments[1] | 9,045 | 750 | 1,050 | 1,350 | 5,895 |
| Long-term debt – interest payments[1] | 7,634 | 422 | 770 | 691 | 5,751 |
| Pension[2] | 172 | 160 | 12 | – | – |
| Environmental and asset retirement obligations[3] | 329 | 32 | 63 | 46 | 188 |
| Inergi LP (Inergi) outsourcing agreement[4] | 152 | 130 | 22 | – | – |
| Operating lease commitments | 48 | 11 | 14 | 14 | 9 |
| **Total contractual obligations** | 17,380 | 1,505 | 1,931 | 2,101 | 11,843 |
| | | | | | |
| **Other commercial commitments** (*by year of expiry*) | | | | | |
| Bank line[5] | 1,500 | – | – | 1,500 | – |
| Letters of credit[6] | 149 | 149 | – | – | – |
| Guarantees[6] | 326 | 326 | – | – | – |
| **Total other commercial commitments** | 1,975 | 475 | – | 1,500 | – |

1 The "long-term debt – principal repayments" amounts are not charged to our results of operations, but are reflected on our Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with the long-term debt is recorded in financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

2 Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2014 minimum pension contributions are based on an actuarial valuation effective December 31, 2011. Minimum pension contributions beyond 2014 will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on future investment returns, changes in benefits, or actuarial assumptions. Pension contributions beyond 2014 are not estimable at this time. On January 30, 2014, we made contributions of $140 million.

3 We record 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. We also record a liability for asset retirement obligations associated with the removal and disposal of asbestos-containing materials installed in some of our facilities, as well as the future decommissioning and removal of two of our switching stations. The forecast expenditure pattern reflects our planned work programs for the periods.

4 In 2002, Inergi began providing services to our company, including business processing and IT outsourcing services. The current agreement with Inergi will expire in February 2015. We have begun developing a plan of action for end-of-term and issued a request for proposal on November 7, 2013. Based on the September 2013 Shareholder Resolution, the Province requires us to contract only with parties who are employed and physically located in Ontario when providing services to our company. The amounts disclosed include an estimated contractual annual inflation adjustment in the range of 1.5% to 3.0%. Payments in respect of our agreement with Inergi are recorded in operation, maintenance and administration costs on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

5 On May 31, 2013, we increased the size of the revolving standby credit facility used to support our liquidity requirements from $1,250 million to $1,500 million, and extended the maturity date from June 2017 to June 2018.

6 We currently have outstanding bank letters of credit of $127 million relating to retirement compensation arrangements. We provide 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, 2013, we have provided letters of credit to the IESO in the amount of $21 million to meet our current prudential requirement. In addition, we have approximately $1 million pertaining to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million, and on behalf of two distributors using guarantees of up to approximately $1 million.

## RELATED PARTY TRANSACTIONS

We are owned by the Province. The OEFC, IESO, OPA, OPG and the OEB are related parties to our company because they are controlled or significantly influenced by the Province.

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to the IESO. The year-over-year changes related to these amounts are described more fully in the discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province, and our PILs and some of our payments in lieu of property taxes, which are paid to the OEFC. In addition, in January 2010, we purchased $250 million of Province of Ontario Floating-Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

Our company receives revenues for transmission services from the IESO, based on OEB-approved UTRs. Transmission revenues include $1,509 million (2012 – $1,474 million) related to these services. Our company receives amounts for rural rate protection from the IESO. Distribution revenues include $127 million (2012 – $127 million) related to this program. Our company 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, our company 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, our company incurred $12 million (2012 – $11 million) in OEB fees.

Our company 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 CDM programs. The funding includes program costs, incentives, and management fees. In 2013, our company received $34 million (2012 – $39 million) from the OPA related to these programs.

Our company 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 our company on April 1, 1999.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are unsecured, interest free and settled in cash.

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) |
| Long-term 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).

## CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

### Effect of Load on Revenue

Our load, based on normal weather patterns, is expected to decline in 2014 due to the impact of CDM and embedded generation, partially offset by load growth associated with economic growth in all sectors of the Ontario economy. Overall load growth due to the economy alone is forecasted to be approximately 1.6%, with the commercial and industrial sectors slightly outperforming the residential sector. The load impacts of CDM and embedded generation are expected to have a negative impact on load growth of approximately 0.4% and 3.5%, respectively. On the whole, our load is expected to decline by about 2.3% in 2014. Our approved revenue requirement for 2014 has taken the expected load decline into account. A reduction in load, beyond our load forecast included in our approved revenue requirement, would negatively impact our financial results.

### Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements upon which our rates are based. The first component impacted by interest rates is our return on equity (ROE). The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. All other things being equal, we estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our ROE would reduce Hydro One Networks' transmission and distribution businesses' 2014 results of operations by approximately $20 million and $10 million, respectively. As interest rates decline, there is more risk of a decline in our net income. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

### Input Costs and Commodity Pricing

In support of our ongoing work programs, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, general outline agreements, and vendor alliances and we also manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts on our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counterparties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

### Pension Plan

In 2013, we contributed approximately $160 million to our pension plan and incurred $287 million in net periodic pension benefit costs, based on an actuarial valuation effective December 31, 2011. Actuarial valuations are minimally required to be filed every three years. We currently estimate our total annual pension contributions to be approximately $160 million for 2014, based on the projected level of pensionable earnings and the same actuarial valuation effective December 31, 2011. Future minimum contributions beyond 2014 will be based on an actuarial valuation effective no later than December 31, 2014. Our pension plan experienced positive returns of approximately 17.91% in 2013. Our pension obligation is impacted by interest rates. The 0.5% increase in the discount rate, from 4.25% at December 31, 2012 to 4.75% at December 31, 2013, resulted in a decrease in the pension obligation of $443 million and an increase to our post-retirement and post-employment benefit obligation of $126 million. Our pension obligation is also impacted by mortality assumptions. The changes in mortality assumptions at December 31, 2013, compared to December 31, 2012, resulted in an increase in the pension obligation of $380 million and an increase to our post-retirement and post-employment benefit obligation of $136 million. Contribution increases are being implemented for all segments of our company's active employees.

## RISK MANAGEMENT AND RISK FACTORS

We have an Enterprise Risk Management (ERM) Program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic goals. Our ERM program helps us to better understand uncertainty and its potential impact on our strategic goals. It sets out the uniform principles, processes and criteria for identifying, assessing, evaluating, treating, monitoring and communicating risks across all lines of business. It supports our Board of Directors' corporate governance needs and the due diligence responsibilities of senior management.

While our philosophy is that risk management is the responsibility of all employees, the Board of Directors annually reviews our company's risk tolerances, risk management policies, processes and accountabilities. Twice per year, the Board of Directors reviews our risk profile, which is the list of key risks prepared by senior management, and represents the greatest threats to meeting our strategic objectives. The Board of Directors' committees review risks relevant to their mandate at every meeting. The Audit and Finance Committee of our Board of Directors annually reviews the status of our internal control framework.

Our President and Chief Executive Officer (CEO) has ultimate accountability for risk management. Our Leadership Team provides senior management oversight of our risk portfolio and our risk management processes. The leadership team provides direction on the evolution of these processes and identifies priority areas of focus for risk assessment and mitigation planning.

Our Chief Administration Officer and Chief Financial Officer (CAO and CFO) is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. The CAO and CFO has specific accountability for ensuring that ERM processes are established, properly documented and maintained by our company.

Our senior managers, line and functional managers are responsible for managing risks within the scope of their authority and accountability. Risk acceptance or mitigation decisions are made within the risk tolerances specified by the head of the subsidiary or function.

The CAO and CFO provides support to the Audit and Finance Committee of our Board of Directors, the President and CEO, the senior management team and key managers within our company. This support includes developing risk management frameworks, policies and processes, introducing and promoting new techniques, establishing risk tolerances, preparing annual corporate risk profiles, maintaining a registry of key business risks and facilitating risk assessments across our company. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems. Starting in 2013, our Board of Directors has taken on an enhanced role in our governance structure. Each committee of the Board of Directors will take accountability for reviewing specific risks of our company.

Key elements of our ERM Program enable us to identify, assess and monitor our risks effectively. These include having an ERM policy and framework which communicates our philosophy and process for risk management across our company. A discussion of risks is an integral part of each line of business' planning documents on an annual basis. Risk identification is also considered as part of each business case for investments. Finally, discrete risk assessments and workshops are performed for specific lines of business, key projects and various profiles, such as customer relationships and regulatory compliance. In order to drive consistency throughout our risk identification and risk management processes, we use a standard list of risk sources known as our risk universe. These sources are maintained in a single database that provides a consistent basis for risk identification and classification and serves as a repository for our risk assessments. All risk assessments in our company start with this risk universe. We also use standard risk criteria, which establish the metrics and terminology used for assessing and communicating on risks, and help ensure a consistent basis for our risk assessments and risk evaluations across all lines of business. Risk criteria include formally established risk tolerances and standard scales for assessing the probability of a risk materializing and the strength of controls in place to mitigate them.

**Ownership by the Province**

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors, appoint the Chair, and influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008 the Province made a declaration removing certain powers from our company's directors pertaining to the off-shoring of jobs under the Inergi Agreement. In 2011, the Province made a declaration preventing our company from seeking cost recovery through the regulatory process for the cost of upgrades required for either Micro FIT or Small FIT generators for costs related to investment and expenditures made. Effective September 30, 2013, the Province made a declaration regarding the outsourcing of services covered by the Inergi Agreement.

In 2009, the Province required our company, among other entities, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Our credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of our company's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, including any potential outcomes arising out of the recommendations of the Ontario Distribution Sector Review Panel's report, the Province's ownership of OPG, and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us, which could have a material adverse effect on our business.

## Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return. The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, our net income for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

The OEB's new Renewed Regulatory Framework requires that the term of a custom rate application (distribution business) is a five-year period. There are risks associated with forecasting over a longer period. Changes in the industry may alter the investment needs or require changes to rate setting that could result in a significant impact on our capability to execute its plan. To mitigate the risk of externally driven factors that may impact its plan, Hydro One Networks proposed a number of adjustment mechanisms in the design of its recent custom application to reflect plan changes outside the normal course of business in order for the Company to avoid a regulatory review by the OEB during the five-year custom application period. Hydro One Networks also proposed a set of outcome measures to track its performance and delivery of the plan. There can be no assurance that the OEB will accept these mechanisms or that they will be sufficient to protect our company from unforeseen changes to its plan.

Our load could also be negatively affected by successful CDM programs. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

We expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

In Ontario, the Market Rules mandate that we comply with the reliability standards established by NERC and Northeast Power Coordinating Council. As a result, we will be required to comply with the Federal Energy Regulatory Commission's definition of the Bulk Electric System unless we are granted an exception which will allow the application of the new definition in a cost-effective manner. We plan to submit exception applications and will look for recovery for costs incurred in meeting the definition in our rates; however, an adverse decision on an exception or recovery of costs could have an adverse effect on our company.

## Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss, we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

**Risk Associated with Information Technology Infrastructure**

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex IT systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats and by providing company-wide awareness training to our personnel. We also engage the services of external experts to evaluate the security of our IT infrastructure and controls. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Upon occurrence, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on our company.

**Risk Associated with Arranging Debt Financing**

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt, including $750 million maturing in 2014 and $550 million maturing in 2015. We plan to incur capital expenditures of approximately $1,600 million in each of 2014 and 2015. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our company.

**First Nation and Métis Claims Risk**

Some of our current and proposed transmission and distribution lines may traverse lands over which First Nations and Métis have aboriginal, treaty or other legal claims. Although we have a recent history of successful negotiations and consultations with First Nations and Métis communities in Ontario, some communities and/or their citizens have expressed an increasing willingness to assert their claims through the courts, tribunals, or by direct action, which in turn can affect business activities. As a result, there exists uncertainty relating to business operations and project planning which could have an adverse effect on our company.

**Risk Associated with Outsourcing Arrangement**

Consistent with our strategy of reducing operating costs, we amended and extended our agreement with Inergi, effectively renewing the arrangement until February 28, 2015. If our agreement with Inergi is terminated for any reason or expires before a new supplier is selected, we could be required to incur significant expenses to transfer to another service provider, which could have a material adverse effect on our business, operating results, financial condition or prospects.

**Risk Associated with Transmission Projects**

The amount of power that can flow through transmission networks is constrained due to the physical characteristics of transmission lines and operating limitations. Within Ontario, new and expected generation facility connections, including those renewable energy generation facilities connecting as a result of the FIT program stemming from the GEA, and load growth have increased such that parts of our transmission and distribution systems are operating at or near capacity. These constraints or bottlenecks limit the ability of our network to reliably transmit power from new and existing generation sources (including expanded interconnections with neighbouring utilities) to load centres or to meet customers' increasing loads. As a result, investments have been initiated to increase transmission capacity and enable the reliable delivery of power from existing and future generation sources to Ontario consumers. In many cases, these investments are contingent upon one or more of the following approvals and/or processes: environmental approval(s); receipt of OEB approvals which can include expropriation; and appropriate consultation processes with First Nations and Métis communities. Obtaining OEB and/or environmental approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments, which could adversely affect transmission reliability and/or our service quality, both of which could have a material adverse effect on our company.

With the introduction on August 26, 2010, of the OEB's competitive transmission project development planning process, in the absence of a government directive, all interested transmitters will be required to submit a bid to the OEB for identified enabler facilities and network enhancement projects. Historically, we would have been awarded such projects through our rates and Section 92 applications. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, bid costs are recoverable only by the successful proponent. This could have a material adverse effect on our company.

**Asset Condition**

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain equipment performance and provide reliable service quality. Our capital programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent upon external factors, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. However, if we are unable to carry out these plans in a timely and optimal manner, equipment performance will degrade, which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security, and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

**Workforce Demographic Risk**

By the end of 2013, approximately 16% of our employees were eligible for retirement, and by the end of 2014, there could be up to 20% eligible to retire. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We are therefore focused on earlier identification and more rapid development of staff who demonstrate management potential. Moreover, we must also continue to advance our technical training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, it could have a material adverse effect on our business.

**Labour Relations Risk**

The substantial majority of our employees are represented by either the Power Workers Union (PWU) or the Society of Professional Energy Workers (Society). Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost-efficient manner. Although we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 similar to a previous reduction affecting management staff and increased pension contributions for PWU and Society staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2015, and the existing Society collective agreement will expire on March 31, 2016. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our company.

**Pension Plan Risk**

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are 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, 2011, and was filed in May 2012. Our company contributed approximately $160 million in respect of 2012 and approximately $160 million in respect of 2013 to its pension plan to satisfy minimum funding requirements. Contributions beyond 2013 will depend on investment returns, changes in benefits and actuarial assumptions and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our company, and this risk may be exacerbated as the quantum of required pension contributions increases.

### Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. However, given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation (LAR) program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's PCB regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025, while our LAR expenditures are expected to be incurred over the period ending 2020. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures. Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities. Actual future expenditures may vary materially from the estimates used for the amount of the asset retirement obligation.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases. We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our company.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our company.

### Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity price risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 40% common equity and 60% debt will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' 2014 net income by approximately $20 million and our Hydro One Networks distribution business' 2014 net income by approximately $10 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest-rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counterparties. We do not trade in any energy derivatives. We do, however, have interest-rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlements Code. The failure to properly manage these risks could have a material adverse effect on our company.

### Risk from Transfer of Assets Located on Reserves

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999, did not transfer title to some assets located on Reserves. Currently, OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy Reserves, we must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the First Nation, OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. Where the agreement and permit are for transmission assets, we must negotiate rental terms. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. In 2013, we paid approximately $2 million to First Nations in respect of these agreements. OEFC will continue to hold these assets until we are able to negotiate agreements with First Nations and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

### Risk from Provincial Ownership of Transmission Corridors

Pursuant to the Reliable Energy and Consumer Protection Act, 2002, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks, which could have an adverse effect on our company.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated Financial Statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities, as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements. We have identified the following critical accounting estimates used in the preparation of our Consolidated Financial Statements:

### Revenues

Our monthly distribution revenue is estimated based on wholesale electricity purchases. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The newly implemented CIS phase of our entity-wide system improvement project will allow us to use historical trends at a customer level to better estimate our unbilled revenue each period. This change in methodology for estimating revenue is anticipated to be implemented in 2014. Any changes in estimate will be accounted for prospectively.

### Regulatory Assets and Liabilities

Our 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. Our regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, and environmental liabilities. Our 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 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 rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgement is made by management.

### Environmental Liabilities

We record 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. 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.

In June 2013, Environment Canada issued Canada Gazette I, which included a proposed amendment to the existing PCB regulations. The proposed amendment would extend the end-of-use deadline for our company's PCBs in concentrations of 500 parts per million or more from December 31, 2014 to December 31, 2025. The proposed amendment is subject to final approvals before the enacted regulation is published in Canada Gazette II. Canada Gazette II is anticipated to be issued in the first half of 2014. An environmental liability is recorded based on regulations as currently enacted, and as such, our environmental liability as at December 31, 2013 is based on the current compliance date of December 31, 2014.

### Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

The discount rate used to calculate the accrued benefit obligation is determined 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 rates at December 31, 2013 increased to 4.75% from 4.25% used at December 31, 2012, in conjunction with increases in bond yields over this period. The increase in discount rates has resulted in a corresponding decrease in liabilities for accounting purposes. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

The assumed return on pension plan assets is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the pension plan's investment policy. Returns on the respective portfolios are determined with reference to published Canadian and US stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the Fund's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. In the short term, the plan can experience aberrations in actual return.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has decreased from 1.9% per annum as at December 31, 2012 to approximately 1.2% per annum as at December 31, 2013. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for liability valuation purposes as at December 31, 2013.

Our pension and post-retirement and post-employment obligations are also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in pension and post-retirement and post-employment benefit obligations.

The costs of post-retirement and post-employment benefits are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of approximately $21 million per year and an increase in the year-end obligation of about $258 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

### Asset Impairment

Within our regulated businesses, the carrying costs of most of our 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. We regularly monitor the assets of our unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2013, no asset impairment had been recorded for assets within our regulated or unregulated businesses.

Goodwill represents the cost of acquired LDCs that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. We have concluded that goodwill was not impaired at December 31, 2013.

## DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

To optimize our customer service operations, we implemented the CIS module of SAP. This new system replaced multiple legacy applications which provided service to our distribution customers and key constituents for billing, customer contacts, field services, settlements, and customer choice administration. Internal controls have been documented and tested for adequacy and effectiveness, and continue to be refined.

In compliance with the requirements of National Instrument 52-109, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2013, together with other financial information included in our securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Further, our 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 our company's DC&P and ICFR, our Certifying Officers concluded that our company's DC&P and ICFR were effective as at December 31, 2013.

## SELECTED ANNUAL INFORMATION

**Consolidated Statements of Operations and Comprehensive Income**

| Year ended December 31 *(millions of Canadian dollars, except amounts per share)* | **2013** | 2012 | 2011 |
|---|---|---|---|
| Revenue | **6,074** | 5,728 | 5,471 |
| Net income | **803** | 745 | 641 |
| Basic and fully diluted earnings per common share | **7,850** | 7,280 | 6,228 |
| Cash dividends per common share | **2,000** | 3,523 | 1,500 |
| Cash dividends per preferred share | **1.375** | 1.375 | 1.375 |

**Consolidated Balance Sheets**

| December 31 *(millions of Canadian dollars)* | **2013** | 2012 | 2011 |
|---|---|---|---|
| Total assets | **21,625** | 20,811 | 18,836 |
| Total long-term debt | **9,057** | 8,479 | 8,008 |
| Preferred shares | **323** | 323 | 323 |

**Other**

| Year ended December 31 *(millions of Canadian dollars)* | **2013** | 2012 | 2011 |
|---|---|---|---|
| Total capital investments | **1,394** | 1,454 | 1,447 |

## 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 our 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 our 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 our Consolidated Financial Statements.

## OUTLOOK

We will achieve our mission and vision and remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our shareholder. We will do this by continuing to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, championing people and culture, shareholder value and productivity and cost-effectiveness.

Given the nature of the work undertaken by our employees and contractors, safety remains our top priority. We will continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives, including maintaining our OHSAS 18001 standing.

We are focused on achieving our long-term vision of improving customer satisfaction, maintaining affordable rates for the portion of the customers' bill within our control and building a trusted partner relationship with our customers. Our plan has taken into account discussions with our customers and reflects the planned development and delivery of targeted customer segment strategies, products and services which respond to our customers' unique needs. This includes realizing value from our new customer information system, simplifying and shortening timeframes for the delivery of services, enhancing accessibility in person, by phone or through our web portal and/or our mobile application to ensure effective self-service for simple transactions and delivering programs which help customers better manage their energy consumption.

We will continue to focus on driving our transformation to a culture that is accountability-based. All of our management staff received training under our Craft of Management program. This program will serve as the foundation for establishing that culture of accountability. Investments in this program, coupled with existing programs which enhance employee skills and ability, will help us deliver best-in-class service to our customers, continue the drive to zero workplace injuries and create a great workplace that will lead to improved employee engagement. We remain focused on managing the resourcing requirements of an increasing work program through appropriate compensation policies, labour negotiations, use of outsourced multi-skilled staff and support of internal and external college and university training programs. Aging workforce demographics provide opportunities, through retirements, to restructure and transform the workforce.

Our assets are in the midst of a demographic change with an increasing proportion of assets reaching the end of their expected service life and an increasing average asset age. To ensure the electricity system's reliability in the public interest, we have planned for significant investments in transmission and distribution infrastructure. Our plan includes targeted, risk-based investments to maintain, refurbish and replace existing assets that are in poor condition and beyond their expected service life, within the policy set by the OEB. Investments in technology, such as the successful implementation of Asset Analytics, has provided us with real-time asset condition and performance data giving us the visibility to make asset optimization life-cycle decisions, and opportunities through planning and scheduling data to improve materials procurement and to deploy work crews to better manage work programs to meet customer needs.

The actual timing and expenditures in our business plan are predicated on obtaining various approvals including: OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities.

We continue to seek to strike the right balance between making prudent risk-based reliability investments and keeping customers' rates low. Effectively and efficiently managing costs is an important part of achieving this balance. Over the last five years, we have replaced most of our core IT systems with an enterprise-wide IT system. Further development of the existing IT platform will provide tools which are being developed to allow us to effectively plan and reprioritize work and integrate customers' needs into multi-year investment plans. This outcome is consistent with the OEB's direction in its new Outcomes-Based Approach to regulation.

Our plan is focused on delivering integrated asset-to-work planning, optimized scheduling and dispatch as well as field mobility. Through our investment in our Workflow of the Future initiative we will bring together data, analytics and mobility to allow our employees, especially those in the field, to do more at the job site with their mobile devices.

Significant opportunity resides with smart meters and the proliferation of an ADS including energy efficiency, demand response and distributed-resource technologies. We will continue to invest in the development of an ADS and related grid modernization standards, customer demand work (connections and upgrades), smart meters, DG connections, including station upgrades, protection and control, new lines and some contestable work, for which we will receive customer capital contributions. There is little flexibility to reduce this work as most of it is customer demand driven.

As stewards of significant electricity assets, we are committed to the protection and sustainment of the environment for future generations. We are working towards being an environmental leader in our industry, by distributing clean and renewable energy, by upgrading our electricity grid, by minimizing the impacts of our own operations, and by ensuring that environmental factors are considered in making our business decisions.

Consistent with our corporate strategy, we will pursue an LDC consolidation approach that is robust but prudent, to facilitate the consolidation of Ontario's distribution sector. This is consistent with the Ontario Distribution Sector Panel's assessment that there are substantial efficiencies to be found through consolidation of Ontario LDCs and we are key to the solution. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects. The OEB notes in its *Framework for Transmission Project Development Plans* that where projects are otherwise equivalent or close in other factors, information such as socio-economic benefits, including First Nations involvement, could prove decisive in a competitive bid. As such, First Nations involvement in competitive bids is likely to become more prevalent.

## APPOINTMENT OF CARMINE MARCELLO

On November 14, 2012, our Board of Directors appointed Carmine Marcello to the role of President and CEO, effective January 1, 2013. Mr. Marcello assumed his responsibilities following the planned retirement of outgoing President and CEO Laura Formusa. Mr. Marcello has over 25 years of experience with our company as a senior executive, strategic planner and advisor on transmission and distribution utility processes in the electric utility industry.

## CHANGES TO OUR BOARD OF DIRECTORS

On November 20, 2013, Sandra Pupatello was appointed to our Board of Directors. Ms. Pupatello is the Director of Business Development and Global Markets at PricewaterhouseCoopers Canada. She is also the Chief Executive Officer of the WindsorEssex Economic Development Corporation.

On November 27, 2013, Catherine Karakatsanis was appointed to our Board of Directors. Ms. Karakatsanis is the Chief Operating Officer of Morrison Hershfield Group Inc. and also serves as Director and Secretary of the Toronto-based consulting engineering firm.

On August 12, 2013, Janet Holder resigned from our Board of Directors. Ms. Holder has been a member of our Board of Directors since July 2010.

## FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy-related revenues and profit and their trend; statements regarding our transmission and distribution rates and customer bills resulting from our rate applications; statements related to the FIT program; statements about CDM; statements about our strategy, including our strategic objectives; statements regarding considerations of current economic conditions; statements related to employee future benefits; expectations regarding First Nation involvement in competitive bids; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility; expectations regarding our financing activities; statements regarding our maturing debt; statements regarding our ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives (including productivity savings, process improvements, and customer satisfaction) and their completion dates; expectations regarding the recoverability of large capital investments; expectations regarding generation connection investments; statements regarding expected future capital and development investments, the timing of these expenditures and our investment plans; expectations regarding OPA recommendations; statements regarding contractual obligations and other commercial commitments; statements related to the OEB; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangement with Inergi and such future outsourcing arrangements; expectations regarding work and costs of compliance with environmental and health and safety regulations; statements related to the LTEP; and statements related to LDC consolidation including our acquisition of 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. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our 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 us, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risk that unexpected capital investments may be needed to support renewable generation or resolve unforeseen technical issues;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the inability to prepare financial statements in US GAAP;
- the impact of the 2010 LTEP and the 2013 LTEP on our company and the costs and expenses arising therefrom;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that the presence of release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the risks associated with information system security, with maintaining a complex information technology system infrastructure, and with transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the risks associated with changes in the forecast long-term Government of Canada bond yield;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction, including regulatory decisions regarding our revenue requirements, cost recovery, rates, acquisitions and divestitures;
- unanticipated changes in electricity demand or in our costs;

- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital investments and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the risks of counterparty default on our outstanding derivative contracts;
- the risks associated with current economic uncertainty and financial market volatility;
- the risk that our long-term credit rating would deteriorate;
- the risk that we may incur significant costs associated with transferring assets located on Reserves (as defined in the *Indian Act* (Canada));
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi is terminated or expires before a new service provider is selected;
- the impact of the ownership by the Province of lands underlying our transmission system; and
- the ability to negotiate appropriate collective agreements.

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

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

Additional information about the Company, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com and on the US Securities and Exchange Commission's website at www.sec.gov.

# 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**
President and Chief Executive Officer

**Sandy Struthers**
Chief Administration Officer and Chief Financial Officer

# 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

# 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.*

# 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.*

# 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

# 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.*

# 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.*

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

**For the years ended December 31, 2013 and 2012**

## 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** | **1** |
| 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%.

# BOARD OF DIRECTORS
(as at December 31, 2013)

**James Arnett[2]**
Chair of the Board of Directors, Hydro One Inc.

**Kathryn A. Bouey[4,6,7]**
President, TBG Strategic Services Inc.

Corporate Director

**Catherine Karakatsanis[4,6]**
Chief Operating Officer, Morrison Hershfield Group Inc.

**Michael J. Mueller[1,2,4]**
Corporate Director

**Robert L. Pace[2,3,7]**
President and CEO, The Pace Group Ltd.

**Sandra Pupatello[1,5]**
Chief Executive Officer, WindsorEssex Economic Development Corporation

Director, Business Development and Global Markets, for PwC Canada

**Douglas E. Speers[3,4,6]**
Corporate Director

**Carmine Marcello**
President and Chief Executive Officer, Hydro One Inc.

**George Cooke[1,5,7]**
President, Martello Associates Consulting

Chair of the Board of Directors of OMERS Administration Corporation

**Don MacKinnon[5,6]**
President, Power Workers' Union

**Walter Murray[1,3,7]**
Corporate Director

**Yezdi Pavri[1,4]**
Corporate Director

**Gale Rubenstein[2,3,5]**
Partner, Goodmans LLP

**Board Committees**

1 *Audit and Finance Committee* The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, financial risk exposures, financial compliance and ethics policies. With the Company's SEC registration in 2013, the Audit and Finance Committee mandate was updated to ensure compliance with U.S. securities legislation. The committee met six times in 2013.

2 *Corporate Governance Committee* The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandate of the Board and each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met seven times in 2013.

3 *Human Resources Committee* The Human Resources Committee is responsible for reviewing the appropriateness of the Company's current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, and the performance and remuneration of senior executives, including recommending to the Board the remuneration of the President and CEO. The committee met seven times in 2013.

4 *Business Transformation Committee* The Business Transformation Committee is responsible for assisting the Board in its oversight responsibilities in all matters related to the Company's Cornerstone Project, the Advanced Distribution System and Continuous Innovation Strategy, and the planning, development and implementation of major transmission system or distribution projects, including projects described in the Corporation's Green Energy Implementation Plan. The committee met seven times in 2013.

5 *Regulatory and Public Policy Committee* The Regulatory and Public Policy Committee monitors the Company's compliance with applicable regulatory requirements and legislation, and is responsible for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have a significant impact on the Company. The committee oversees compliance programs, policies, standards and procedures and reviews the Company's proposals for rate applications, compliance actions and reports. The committee met five times in 2013.

6 *Health, Safety and Environment Committee* The Health, Safety and Environment Committee is responsible for reviewing occupational health, safety and environment policies, standards, and programs, compliance with occupational health, safety and environmental legislation, policies and standards, and public health and safety issues. The committee met four times in 2013.

7 *Investment – Pension Committee* The Investment – Pension Committee's primary function is to assist the Board in fulfilling its oversight responsibilities in all matters related to the Corporation's Pension Plan including the Hydro One Pension Fund. The committee met five times in 2013.

### Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution, and telecom services.

### Hydro One Networks Inc.
Represents the majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

### Hydro One Brampton Networks Inc.
Distributes electricity to one of the fastest-growing urban centres in Canada, just 30 kilometres outside of Toronto.

### 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 province's electricity transmission grid.

### Hydro One Telecom Inc.
Markets our fibre-optic capacity to business customers. This business represents less than one per cent of our total assets.

---

## CORPORATE INFORMATION

### Corporate Address
483 Bay Street
Toronto, Ontario M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com

### Investor Relations
(416) 345-6867
investor.relations@HydroOne.com

### Media Inquiries
(416) 345-6868
1-877-506-7584

### Customer Inquiries
Power outage and emergency number:
1-800-434-1235

Residential, farm and small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

### Auditors
KPMG LLP


MAMMO

To learn more about what Hydro One is doing to deliver electricity, build for the future and keep the environment healthy, visit

**www.HydroOne.com**

# CUSTOMER **FOCUSED**

ANNUAL REPORT 2014

hydro One

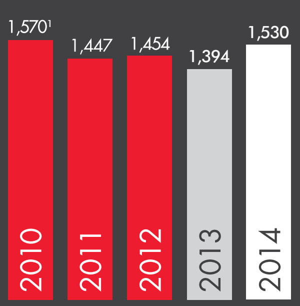
We are customer focused, from the inside out. In our delivery of safe, reliable and responsible power, we know that we must look to our customers' needs in everything we do. **More than 1.3 million homes and businesses across Ontario rely on us. And we will deliver.**

# OUR FOCUS

## CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

### CAPITAL INVESTMENTS

(CAD $ millions)

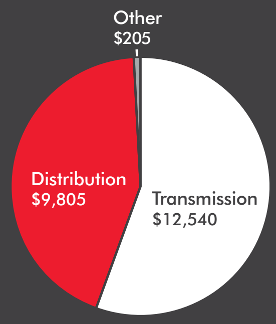



[1] based on Canadian GAAP

### TOTAL ASSETS

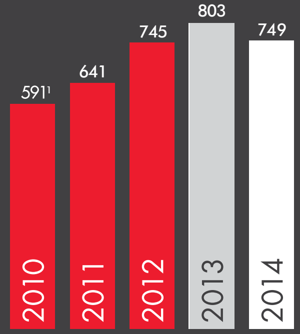
December 31, 2014

(CAD $ millions)




### NET INCOME

(CAD $ millions)




[1] based on Canadian GAAP

**1.8**

recordable injuries per 200,000 hours worked, a decrease from 2.5 in 2013

**12,000 km**

The Electricity Discovery Centre travelled more than 12,000 kilometres between September 2013 and September 2014

**$224 m**

In 2014, Hydro One invested more than $224 million in Ontario's transmission system to increase electricity reliability in Toronto and the Greater Toronto Area

**60,000**

Hydro One spoke to more than 60,000 customers during three tele-townhalls in 2014

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# IS ON YOU

| *Year ended December 31 (CAD $ millions, except as otherwise noted)* | **2014** | 2013 | Change | % Change |
|---|---|---|---|---|
| Revenues | **6,548** | 6,074 | 474 | 8 |
| Purchased power | **3,419** | 3,020 | 399 | 13 |
| Operating costs | **1,914** | 1,782 | 132 | 7 |
| Net income | **749** | 803 | (54) | (7) |
| Net cash from operating activities | **1,256** | 1,404 | (148) | (11) |
| Average annual Ontario 60-minute peak demand *(MW)*[1] | **20,596** | 21,493 | (897) | (4) |
| Distribution – units distributed to our customers *(TWh)*[1] | **29.8** | 29.8 | | |

[1] System-related statistics are preliminary.

# LETTER FROM THE CHAIR

"Of all the firsts in 2014, the one that speaks to me the most is the commercial partnership between our Company and the Saugeen Ojibway Nation to own the Bruce to Milton transmission line. This is the first time in the Company's history that we have partnered with a First Nation on a commercial basis."

The people of Ontario count on Hydro One to reliably deliver the electricity necessary for their families, their businesses and their communities to thrive. They also count on Hydro One to operate effectively in a commercial fashion and make a vital financial contribution to the Province of Ontario, its sole shareholder.

In 2014, the Company focused its efforts on improving customer service, enabling the connection of new energy sources and making the right investments to ensure that Ontario's grid is strong today and ready for the future.

From a financial standpoint, Hydro One's net income in 2014 reached $749 million, with revenues of $6,548 million for the year.

Our 2014 revenues increased by $474 million compared to 2013's revenues of $6,074 million. The increase was due to higher Ontario Energy Board-approved 2014 transmission rates, the recovery of higher purchased power costs, and the OEB's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions.

Hydro One paid dividends of $287 million to the Province in 2014.

One of the Company's top priorities in 2014 was improving Hydro One's level of customer service. A number of internal and external initiatives across the Company were introduced, including Hydro One's Customer Service Advisory Panel and a customer consultation process to ensure we made things right for our customers.

There were many firsts for the Company in 2014 in the areas of research and innovation. For example, we acquired two unmanned aerial vehicles for our Kleinburg Training Centre. These drones will be primarily used for training purposes and work to use them to test our transmission lines is underway across various departments.

Of all the firsts in 2014, the one that speaks to me the most is the commercial partnership between our Company and the Saugeen Ojibway Nation to own the Bruce to Milton transmission line. This is the first time in the Company's history that we have partnered with a First Nation on a commercial basis.

I would like to thank all Hydro One employees, senior management and my colleagues on the Board for their dedication and commitment to the Company and the people of Ontario.

**Sandra Pupatello**
Chair of the Board of Directors

# LETTER FROM THE PRESIDENT AND CEO

"We are committed to delivering cost-effective service to all our customers and we remain focused on prudent management, efficient operations and improving the customer experience for everyone we serve."

In 2014, Hydro One concentrated on achieving its goal of becoming Canada's leading utility by 2019. How will we know when we have arrived? The true measure of success will be when our customers, shareholder and employees believe we are a company of great people providing real value and safe, reliable and responsible service. We will only get there if we focus on transforming our culture, get better at our jobs every single day and manage our business effectively.

Hydro One's strong financial performance in 2014 demonstrated our commitment to delivering results for our shareholder as well as our dedication to operating a well-managed business.

During 2014, we put tremendous effort into serving our customers and building stronger relationships. Service levels at our call centre and of our billing system are now better than ever and we have set new targets that, when achieved, will put us among the best in the business.

We moved forward on our journey by investing in our system to replace aging assets and put in place new infrastructure required to deliver the electricity that Ontario needs. Our 2014 Transmission Business capital investments included the replacement of end-of-life power transformers at our Pembroke Transmission Station in eastern Ontario, and at our Hanover, Allanburg, Elmira, and Trafalgar transmission stations in southwestern Ontario. We also received an approved Environmental Assessment to construct the Clarington Transformer Station, critical to keeping the lights on for more than one million Ontarians after the Pickering Nuclear Generating Station shuts down in 2020.

Within our distribution business, our 2014 capital investments included replacement of meters and end-of-life wood poles, work within our station and lines programs, new customer connections and upgrades, and system capability reinforcement projects.

Last year, we completed the acquisition of Norfolk Power Inc., an electricity distribution and telecom company located in southwestern Ontario. We have also reached agreements to acquire two more local distribution companies in southwestern Ontario, Woodstock Hydro and Haldimand Hydro. Consolidating our operations with smaller utilities in our service territory will remain an opportunity to drive growth for Hydro One and improve value for our customers.

We are committed to delivering cost-effective service to all our customers and we remain focused on prudent management, efficient operations and improving the customer experience for everyone we serve.

I would like to thank our Board of Directors for their support, my leadership team for their dedication and our employees for their commitment to working safe, working hard and working to change. They wear the Hydro One logo with pride.

**Carmine Marcello**
President and Chief Executive Officer

# CUSTOMER SERVICE

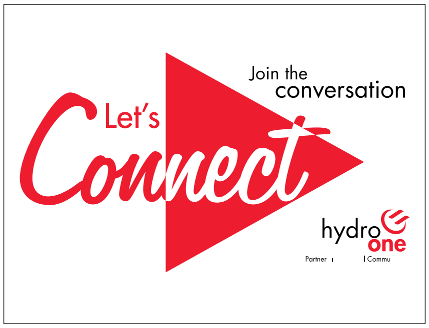
## OUR FOCUS IS ON YOU

Hydro One believes a well-managed company is a customer-driven company. The people of Ontario deserve safe, reliable and responsible power. We can only achieve this with a strong customer service culture – a culture that remains transparent, accountable and fair.

Hydro One spoke to more than 60,000 customers during three tele-townhalls in 2014.

## CUSTOMER COMMITMENTS

In 2014, Hydro One hosted three tele-townhalls to reach out to our customers to gather their feedback on how we can serve them better. In the townhalls, we spoke to more than 60,000 customers from across Ontario and the concerns they expressed led to the creation of a customer consultation process in October where we began developing a series of Customer Commitments. We further reached out to customers with our Let's Connect survey to gather additional feedback on our customer service practices.




## CUSTOMER SERVICE ADVISORY PANEL

October also saw the launch of Hydro One's third-party Customer Service Advisory Panel to advise us on how we can improve our customer service culture and deliver on our customer service promises. The body is made up of industry-leading experts from several sectors, including finance, education and technology. The panel meets regularly to assess our performance against stated objectives and holds us accountable for our actions.

## CUSTOMER RECOVERY PROCESS

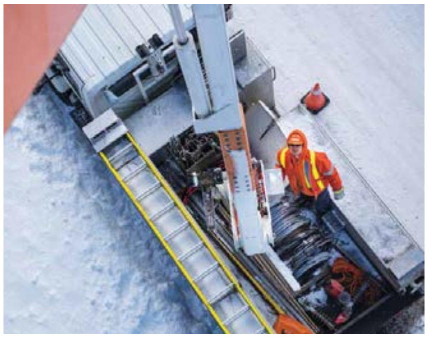
Our path to becoming Canada's leading utility is one of change. In 2014, we introduced major changes across all lines of business to truly become one company. We knew we had to make things right for our customers. In early 2014, at the height of our customer service disruptions with our billing system, approximately 5 per cent of our customers hadn't received a bill for more than three months. By December 2014, that figure had dropped to less than 1 per cent.

Other changes in 2014 to transform our customer service culture included improvements made at our call centre and the launch of a Call-A-Customer program where senior managers from different lines of business contact customers. As well, we revamped our Quality Program in the call centre, with a heightened attention to connecting customers and providing service excellence.

Service levels at our call centre are now better than they were before we implemented our new billing system in May 2013. We have set new targets that, when achieved, will put us among the best in the business. Overall, customer satisfaction has shown a steady increase since early 2014, with a weekly high of 93 per cent of customers satisfied with their call centre interaction.

## LINES AND FORESTRY PARTNERSHIP

The year saw a deepening of an already powerful partnership between our Provincial Lines and Forestry Services. What began as a small modification to a zone map has led to a strong partnership that is evident across all levels of the organization. This has resulted in improved customer service, reduced operating costs and shorter storm response times.



## REDESIGN OF HYDROONE.COM HOME PAGE

In October, we redesigned the HydroOne.com home page to include a featured stories section to inform our customers about our employees, current projects and the good work we are doing in communities across Ontario.

# SAFETY

## WE PUT SAFETY FIRST IN EVERYTHING WE DO

The safety of our employees and the people of Ontario guides our decisions. We are focused on delivering value to our customers in a fair, safe and responsible manner. We know that safety is *every* employee's responsibility.

In July, Hydro One's Owen Sound crew celebrated one million hours worked without a lost time injury or illness and no recordable injuries over the past three years.

## JOURNEY TO ZERO

Hydro One continued our work with Journey to Zero in 2014, reinforcing employee involvement and engagement by instilling the belief that all injuries are preventable, as well as creating effective Health and Safety communication across the Company and establishing local health and safety goals and objectives.

## OHSAS 18001

Hydro One maintained its Occupational Health and Safety Assessment Series (OHSAS) 18001 certification in 2014 due to a continuous improvement strategy to help us prepare for future surveillance audits. The Company was OHSAS 18001 certified in June 2013, demonstrating that we have the elements of a world-class health and safety system in place.

## MOVE TO AN INJURY-FREE WORKPLACE

One of our goals is to become a world-class utility by 2019. Our year-end safety performance in 2014 helped us work toward this goal with 1.8 recordable injuries[1] per 200,000 hours worked. That number decreased from 2013 when Hydro One reported 2.5 medical attentions per 200,000 hours worked. The Company has also seen a reduction in both "High MRPH" (Maximum Reasonable Potential for Harm) incidents and the number of preventable motor vehicle accidents in the last few years. In 2014, Hydro One used recordable rates as its corporate safety metric to allow for better performance benchmarking with North American and international industries.

## REDUCING DISTRACTED DRIVING

Nothing is more important than the health and safety of our employees and the people of Ontario. Acting on that belief, we introduced a standard in April to prohibit the use of hands-free electronic devices, including smartphones, for all employees who are operating a motor vehicle on Company business. Employees are encouraged to pull over to the side of the road, where it is safe, if they need to handle a call, text or email. The standard takes Section 78.1 of the *Highway Traffic Act* a step further by prohibiting the use of the hands-free options while driving.

## BUILDING A SAFE WORKPLACE CULTURE

From proper job planning to a trained and competent workforce, throughout 2014 Hydro One emphasized the importance of a safe workplace culture across all lines of business. The Company introduced nine core principles around its Safe Workplace Vision in 2014. The nine principles focus on continuous improvement and health and safety at Hydro One.

## EMPLOYEE ENGAGEMENT

Engaged employees are safer employees. In 2014, we measured employee engagement as it related to our core values, best business practices and health and safety initiatives. Engaged employees had fewer sick days, reported fewer recordable incidents and were less likely to get hurt compared to less engaged employees. Our findings illustrate how strong employee engagement drives our Company's success, enabling us to reach our stated objectives.

## OWEN SOUND CREW REACHES SAFETY MILESTONE

In July, Hydro One's Owen Sound crew celebrated one million hours worked without a lost time injury or illness and no recordable injuries over the past three years. The milestone took 14 years to accomplish, and was achieved through proper job planning, teamwork and creating a strong safety culture among all employees.

[1] A recordable injury is a work-related injury or illness that results in:

- Restricted work,
- Lost time,
- Loss of consciousness,
- Medical attention beyond first aid,
- Death, or
- Any other significant work-related injury or illness diagnosed by a physician or other health care professional.

# RELIABILITY

## CONNECTING ONTARIO TO WHAT MATTERS

The people of Ontario depend on Hydro One as stewards of Ontario's electricity system to deliver safe and reliable electricity to power their lives. Our employees are committed to providing this level of service.

In 2014, Hydro One invested more than $224 million in Ontario's transmission system to increase electricity reliability in Toronto and the Greater Toronto Area.

## CLARINGTON TRANSFORMER STATION

Hydro One received the final Environmental Assessment approval in 2014 for the Clarington Transformer Station (TS) project. Clarington TS will enable future electricity growth in the local area and address growing electricity demands in the east Greater Toronto Area (GTA). Once completed, the station will serve one million customers in the east GTA.

## MAJOR INVESTMENTS

During 2014, we made capital investments totalling approximately $1.5 billion to improve our transmission and distribution systems' reliability and performance, address our aging power system infrastructure, facilitate new generation, and improve service to our customers throughout Ontario.

Our total capital investments included transmission system investments of more than $224 million to increase electricity reliability and support the energy needs in the GTA. Given the aging of our infrastructure, our ongoing investment plans are designed to reliably power our economy and to support the innovation that can be expected over the next decade.

## ORLÉANS OPERATIONS CENTRE

In accordance with our commitment to improve reliability for our customers, in January we opened the permanently located Orléans Operations Centre, outside of Ottawa. The centre will benefit Orléans, Navan, Rockland and surrounding areas and serve roughly 39,000 customers. The centre is part of a $33.4 million investment in a new transmission line to meet growing electricity needs in the area.

## WOOD POLES REPLACEMENT

Throughout 2014, Hydro One continued its wood pole replacement program – replacing 11,000 wood poles across Ontario. This proactive program targets poles more than 60 years old across our 122,000-kilometre system. With 1.6 million wood poles in our distribution system, more than 340,000 will need replacing in the next 10 years. The $82 million investment is part of an ongoing effort to make notable upgrades to system reliability and maintain public safety.

**11,000**

wood poles replaced in 2014

## ACQUISITION OF NORFOLK POWER

In 2014, we completed the acquisition of Norfolk Power Inc., a local distribution and telecom company in southwestern Ontario. Hydro One also reached an agreement to acquire Woodstock Hydro Holdings Inc., which is pending Ontario Energy Board approval.

Our major 2014 GTA investments include:

| | |
|---|---|
| Main Transmission Station, Toronto | $9.1 million |
| Toronto Lakeshore Infrastructure Renewal | $53 million |
| Bridgman Transmission Station, Toronto | $12.3 million |
| Leaside Transmission Station, Toronto | $7.2 million |
| Basin Transmission Station, Toronto | $7 million |
| Claireville Transmission Station, Woodbridge | $5.5 million |
| Cooksville Transmission Station, Mississauga | $32.1 million |
| Manby Transmission Station, Toronto | $5.8 million |
| Gerrard Transmission Station, Toronto | $10 million |
| Trafalgar Transmission Station, Oakville | $15 million |

# EXECUTION EXCELLENCE

## CONTINUOUS IMPROVEMENT POWERS THE FUTURE. EXCELLENCE ENABLES IT.

From our innovative Move to Mobile project to our research into the use of drones to inspect our transmission lines, we are committed to providing the people of Ontario with reliable and innovative initiatives to power them into the future.

Hydro One's mobile outage app received 51,067 downloads in 2014.

## B2M LP WITH THE SAUGEEN OJIBWAY NATION

A first in Canada, Hydro One partnered with the Saugeen Ojibway Nation (SON) to create a limited partnership (B2M LP) to own the Bruce to Milton transmission line – a double-circuit, 500 kV line between the Bruce Nuclear Generating Station in Kincardine and our Milton Switching Station. The line – completed in 2012 – has the capacity to transmit 3,000 MW of clean, renewable energy. The SON owns a 34 per cent interest in B2M LP while Hydro One is the majority unitholder. Operations for B2M LP commenced in December 2014.

## MOVE TO MOBILE PROJECT

Hydro One's Move to Mobile project is the first step in a multi-year program to enhance our existing work processes and planning by introducing industry-leading mobile capabilities. The program launched in August and will equip our workforce with a new mobility solution to perform daily tasks wherever they are in the province.

## LAMBTON TO LONGWOOD CONNECTION

In September, we completed a $24 million upgrade to a transmission circuit between Lambton Transmission Station and Longwood Transmission Station in southwestern Ontario. The investment refurbished 36 tower foundations, replaced the circuit with a higher capacity wire and replaced insulators along the line – allowing for approximately 500 MW of renewable generation to be connected. This project used the Aluminum Conductor Steel Supported conductor for the first time in our Company's transmission system. This lightweight wire increases the line's current carrying capabilities without the need to rebuild existing towers.

## DRONE TESTING

In the fall, Hydro One acquired two drones. A first for the Company, the drones will be housed at Hydro One's Kleinburg Training Centre and will be used primarily for training purposes. Work to use the drones to test our transmission lines is underway.

## MOBILE APP

The Company's mobile outage app received 51,067 downloads in 2014, totalling more than 230,000 downloads since it launched in May 2012. The app connects our customers with our interactive outage mapping system, allowing them to receive detailed and updated power outage information from anywhere in our service area.

# SENIOR MANAGEMENT

**Carmine Marcello**
President and
Chief Executive Officer,
Hydro One Inc.

**Joe Agostino**
Senior Vice President
and General Counsel

**Laura Cooke**
Senior Vice President
Customer and
Corporate Relations

**John Fraser**
Senior Vice President
Internal Audit

**Judy McKellar**
Senior Vice President
People and Culture/
Health, Safety and
Environment

**Colin Penny**
Senior Vice President
Technology and
Chief Information Officer

**Gary Schneider**
Vice President
Shared Services

**Ali Suleman**
Chief Financial Officer
(Acting)

**Sandy Struthers**
Chief Operating Officer
and Executive Vice
President Strategic
Planning

# MANAGEMENT'S DISCUSSION AND ANALYSIS

**For the years ended December 31, 2014 and 2013**

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 Inc. (Hydro One or the Company) for the year ended December 31, 2014. 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. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which are different from those of the US. This MD&A provides information for the year ended December 31, 2014, based on information available to management as of February 11, 2015.

## EXECUTIVE SUMMARY

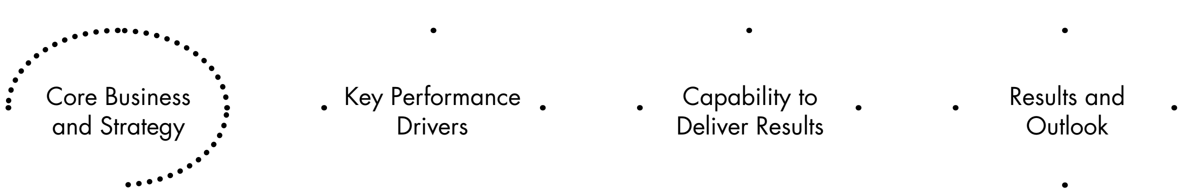
We are wholly owned by the Province of Ontario (Province or Shareholder), and our Transmission and Distribution Businesses are regulated by the Ontario Energy Board (OEB).

During 2014, we continued to focus tremendous effort on customer service and on forming a stronger relationship between our customers' satisfaction with our service and their perceptions of our company. The expectation is that in doing so, we will emerge from the challenges of this year with a renewed, transparent and consistent experience for all our customers by creating new customer tools, products, and processes and by establishing new standards for customer service. We have implemented a strong governance system that will ensure we are monitoring and measuring key performance indicators to support and advance our values with respect to being a customer caring company. We have achieved a number of targets with respect to call centre performance and billing issues to stabilize customer operations following the implementation of our new billing system, and we will continue to strive for stronger performance and an ever-improving experience for our customers.

To further improve our customer service performance culture, we have recently announced two new initiatives – a third party expert Customer Service Advisory Panel and our draft Customer Commitments. Our Customer Commitments will form the basis of our promises to our customers, and the Customer Service Advisory Panel will provide advice and hold us accountable to the promises we make to our customers. Once our Customer Commitments are finalized with input received from our customers, our employees and our Customer Service Advisory Panel, we will develop a public scorecard and will report on our performance as a transparent, accountable and customer focused organization.

Our mission and vision reflects the unique role we play in the economy of the Province and as a provider of critical infrastructure to all our customers. We strive to be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety; excellence; stewardship; and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial, transparent and which values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers.

We manage our business using the following framework:



## Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic objectives, which are discussed in the section "Overview – Our Strategy," encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; Shareholder value; and productivity.

## Key Performance Drivers

Performance drivers have been identified that relate to achieving our company's strategic objectives. We establish specific performance targets for each driver aimed at measuring the achievement of our strategic objectives over time. For example, we track the duration of unplanned customer interruptions per delivery point as an indication of our commitment to provide a reliable transmission system for our customers. We measure transmission and distribution unit costs as an indication of our commitment to increasing productivity. These and other key performance drivers are included in the discussion of our performance measures in the section "Overview – Performance Measures and Targets."

## Capability to Deliver Results

We continue to use a balanced scorecard approach as we strive to manage our performance and deliver results each and every year. In 2014, we set 14 performance measure targets and we met or exceeded eight of them. We exceeded our targets for an injury-free workplace, timely and efficient connection of new customers, the ability to provide timely and accurate bills to customers, our Transmission Business cost-effectiveness, net income after tax, and our transmission and distribution in-service capital. Our targets, and our 2014 performance relating to these targets, are discussed in the section "Overview – Performance Measures and Targets." Our ability to deliver results in each of our strategic areas is limited by risks inherent in our regulatory environment, our business, our workforce, and in the economic environment. These risks, as well as our strategies to mitigate them, are discussed in the section "Risk Management and Risk Factors."

## Results and Outlook

**Consolidated Statements of Operations and Comprehensive Income**

| *Year ended December 31*<br>*(millions of Canadian dollars, except per share amounts)* | **2014** | 2013 | 2012 |
|---|---|---|---|
| Total revenue | **6,548** | 6,074 | 5,728 |
| Net income attributable to the Shareholder of Hydro One | **749** | 803 | 745 |
| Basic and fully diluted earnings per common share *(dollars)* | **7,319** | 7,850 | 7,280 |
| Cash dividends per common share *(dollars)* | **2,696** | 2,000 | 3,523 |
| Cash dividends per preferred share *(dollars)* | **1.375** | 1.375 | 1.375 |

**Consolidated Balance Sheets**

| *December 31 (millions of Canadian dollars)* | **2014** | 2013 | 2012 |
|---|---|---|---|
| Total assets | **22,550** | 21,625 | 20,811 |
| Total long-term debt | **8,925** | 9,057 | 8,479 |
| Preferred shares | **323** | 323 | 323 |
| Net assets | **7,947** | 7,415 | 6,830 |

During 2014, we earned net income of $749 million and revenues of $6,548 million. We made capital investments totalling $1,530 million to improve our transmission and distribution systems' reliability and performance, address our aging power system infrastructure, facilitate new generation, and improve service to our customers. A full discussion of our results of operations, financing activities, and capital investments can be found in the sections "Annual Results of Operations" and "Liquidity and Capital Resources."

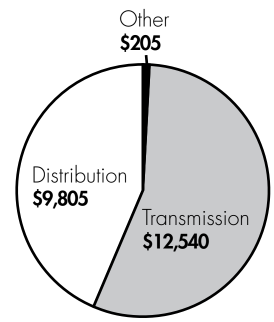
In August 2014, we completed the acquisition of Norfolk Power Inc. (Norfolk Power), an electricity distribution and telecom company located in southwestern Ontario. Hydro One has been a proud electricity distributor in Norfolk County for decades, serving approximately 14,000 Norfolk County customers. The acquisition of Norfolk Power enables our company to extend our service to the entire Norfolk County and a further 18,000 distribution customers. We are committed to delivering cost-effective service for Norfolk Power's customers and we remain focused on prudent management, efficient operations and improving the customer experience for everyone we serve. In 2014, we also signed agreements to purchase two more local distribution companies (LDCs): Woodstock Hydro Holdings Inc. (Woodstock Hydro) and Haldimand County Utilities Inc. (Haldimand Hydro). A full discussion of the Norfolk Power, Woodstock Hydro and Haldimand Hydro acquisitions can be found in the section "New Developments in 2014 – Business Combinations."

In addition, we have completed a partnership transaction with the Saugeen Ojibway Nation (SON), where the SON has acquired a noncontrolling equity interest in our new limited partnership, B2M Limited Partnership (B2M LP). A full discussion of this transaction can be found in the section "New Developments in 2014 – Business Combinations."

## OVERVIEW

We are the largest electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario's electricity transmission system, accounting for approximately 97% of Ontario's transmission capacity based on revenue approved by the OEB. Based on assets, our transmission system is one of the largest in North America. Our consolidated distribution system is the largest in Ontario and spans roughly 75% of the province.

**Total Assets**
December 31, 2014
*(millions of dollars)*




### Our Businesses

Our company has three reportable segments:

- Our Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- Our Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- Other Business, which includes certain corporate activities and the operations of our telecommunications business.

***Transmission Business***

| | **2014** | 2013 |
|---|---|---|
| Electricity transmitted *(TWh)*[1] | **139.8** | 140.7 |
| Ontario 20-minute system peak demand *(MW)*[1] | **23,040** | 24,957 |
| Ontario 60-minute system peak demand *(MW)*[1] | **22,774** | 24,927 |
| Total transmission lines spanning the province *(circuit-kilometres)* | **29,344** | 29,344 |
| Transmission stations *(#)* | **290** | 285 |
| Transmission transformers *(#)* | **1,471** | 1,416 |
| Transmission customers *(approximate #)* | **5,000,000** | 5,000,000 |

[1] System-related statistics include preliminary figures for December.
TWh means terawatt-hours
MW means megawatts

Our transmission system totals approximately 29,000 circuit-kilometres of high-voltage lines whose major components consist of cables, conductors, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems. We also own 290 transmission stations and over 1,400 transmission transformers. Our transmission system operates at 500 kV, 230 kV and 115 kV over relatively long distances and transmits electricity from hydroelectric, wind, solar, nuclear and coal-burning generators to customers consisting of 46 LDCs, our own distribution businesses, and 90 transmission-connected companies. It is also linked to five adjoining jurisdictions through 26 interconnections, through which we can accommodate electricity imports of up to 6,963 MW, and electricity exports of up to 6,295 MW. During 2014, our transmission system transported approximately 139.8 TWh of energy throughout Ontario.

Our Transmission Business includes the transmission businesses of our subsidiary Hydro One Networks Inc. (Hydro One Networks) as well as B2M LP. We own and operate substantially all of Ontario's electricity transmission system, and serve, directly or indirectly, approximately five million customers. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre.

In 2014, we earned total transmission revenues of $1,588 million, representing approximately 24% of our total 2014 revenues. At December 31, 2014, our Transmission Business assets were $12,540 million, representing approximately 56% of our total assets.

### *Distribution Business*

| | **2014** | 2013 |
|---|---|---|
| Electricity distributed to Hydro One customers *(TWh)*[1] | **29.8** | 29.8 |
| Electricity distributed through Hydro One lines *(TWh)*[1,2] | **42.4** | 42.5 |
| Total distribution lines spanning the province *(circuit-kilometres)* | **123,657** | 122,853 |
| Distribution wood poles *(approximate #)* | **1,551,000** | 1,550,000 |
| Distribution and regulating stations *(#)* | **1,026** | 1,017 |
| Distribution customers *(#)* | **1,439,321** | 1,420,379 |

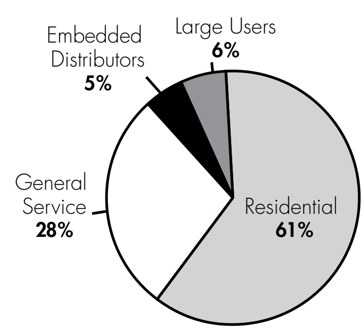
[1] System-related statistics include preliminary figures for December.

[2] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Our distribution system totals over 123,000 circuit-kilometres of distribution lines, and we own over 1,000 distribution and regulating stations and over 1.5 million distribution wood poles. Our distribution system distributes electricity from our transmission system and from more than 14,200 small generators to approximately 1.4 million of our rural and urban customers within Ontario. During 2014, approximately 42.4 TWh of electricity was distributed through our distribution system, including 29.8 TWh of electricity delivered to Hydro One customers.

Our consolidated Distribution Business includes the distribution businesses of our subsidiary Hydro One Networks and the newly acquired Norfolk Power, as well as our subsidiaries Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), and Hydro One Remote Communities Inc. (Hydro One Remote Communities).

**2014 Distribution Revenues**




- Hydro One Networks' distribution business operates a low-voltage electrical distribution network that distributes electricity to customers, including 23 LDCs not directly connected to our transmission system, 33 LDCs connected to our transmission system, 31 customers with loads exceeding 5 MW, and approximately 1.3 million rural and urban customers.
- Hydro One Brampton Networks operates the electricity distribution system and facilities within the City of Brampton, Ontario, serving approximately 150,000 urban retail customers.
- Hydro One Remote Communities operates 19 small, regulated generation and distribution systems in 21 remote communities across northern Ontario that are not connected to Ontario's electricity grid, serving approximately 3,500 customers.

In 2014, we earned total distribution revenues of $4,903 million, including cost of purchased power of $3,419 million, representing approximately 75% of our total 2014 revenues. At December 31, 2014, our Distribution Business assets were $9,805 million, representing approximately 43% of our total assets.

***Other Business***

Our Other Business segment includes the operations of our subsidiary, Hydro One Telecom Inc. (Hydro One Telecom), which operates a fibre optic communications network spanning over 6,000 kilometres. Hydro One Telecom provides dark fibre and lit fibre optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario. Hydro One Telecom also provides telecommunication systems management and related functions which are required for our transmission and distribution businesses, including corporate data and voice networks and smart meter operations.

In 2014, our Other Business segment contributed revenues of $57 million, representing approximately 1% of our total 2014 revenues. At December 31, 2014, our Other Business segment assets were $205 million, representing approximately 1% of our total assets.

## Our Strategy

Our corporate strategy builds on our strong commitment to the Province and is shaped by our values. It lays out a set of objectives to position our company to achieve our mission and vision, which is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs.

- *Health and safety:* Nothing is more important than the health and safety of our employees, those who work on our property, and the public.
- *Excellence:* We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and affordable service, with integrity.
- *Stewardship:* We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.
- *Innovation:* We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that are inextricably linked. They drive the fulfillment of our mission and vision and ensure we remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our Shareholder.

- *Creating an injury-free workplace and maintaining public safety.* Health and safety must be integrated into all that we do as we continue to reinforce that nothing is more important than the health and safety of our employees. We will continue to create a passion for preventing injury, staying safe and keeping each other safe. We will invest in building a culture of accountability to continue our drive to zero injuries in the workplace. In addition, we will continue to strengthen our already strong safety culture through our Journey to Zero initiative and our successful certification to the Occupational Health and Safety Assessment Series (OHSAS) 18001 standard.
- *Satisfying our customers.* We exist to serve our customers, and serving our customers means reducing costs, improving customer service and meeting their expectations regarding reliable power supply. We will continue to focus our efforts to improve our relationship with customers and to improve our customers' satisfaction with us. We will meet our commitments, make customers our focus in all planning discussions, communicate effectively, coordinate across our company, and maximize opportunities to improve our corporate image and every customer interaction. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs.
- *Continuous innovation.* Innovation represents one of our values and is critical to achieving our mission and vision. We have been using innovation and technology to build the foundation of our company as the utility of the future. Over the next two decades, we will continue to build on that foundation to improve the reliability and efficiency of our transmission and distribution systems and provide our customers with more capability to manage their power costs. The development of the Advanced Distribution System (ADS) is a key element in our investment in innovation, as are the investments we have made, through our Cornerstone project, in next-generation business tools to enable us to implement leading industry practices and increase productivity.

- *Building and maintaining reliable, affordable transmission and distribution systems.* Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on continuing to meet the challenge of providing reliable, affordable service to our customers in a wide range of geographical regions and climate zones; incorporating ADS technology to provide greater visibility; and increased control and improved customer service. We will meet customer expectations regarding reliability, in part through our investment planning process, which starts with the identification of asset and customer needs.
- *Protecting and sustaining the environment for future generations.* Consistent with our value of stewardship, we play a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use.
- *Championing people and culture.* We believe our primary strength is the capability of our people. In order to sustain this advantage, we will continue to address the issues of corporate culture, labour demographics, diversity, development of critical core competencies, and skill and knowledge retention. We will continue to develop a culture of accountability and trust as a key component to fostering employee engagement. Our labour strategy is to consolidate and clarify our collective agreements, increase flexibility and reduce costs, and maintain a progressive relationship with our unions.
- *Maintaining a commercial culture that increases value for our Shareholder.* For the delivery component of a customer bill, we are committed to maintaining total annual bill impacts for an average residential customer at or below the rate of inflation, and delivering income and dividends to our Shareholder. We will pursue growth opportunities through LDC consolidation to increase the enterprise value of our company by leveraging our existing assets, technologies, capabilities, unparalleled experience in LDC acquisitions, and our distribution and transmission footprint.
- *Achieving productivity improvements and cost-effectiveness.* To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our Shareholder.

## Performance Measures and Targets

We target and measure our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we maintain a focus on our strategic objectives and take mitigating actions as required. In 2014, we met or exceeded eight of 14 performance measure targets. Overall, we are making progress towards achieving many of our strategic goals.

### *Injury-free Workplace*

The safety of our employees is paramount. For 2014, our company used the measure of all work-related injuries or illnesses as the performance measure for this strategic objective. A "recordable" injury/illness is one of the following: medical attention (treatment beyond first aid); modified work (restricted duties); lost time; or death. For 2014, our Board of Directors set the target at 1.9 recordable injuries per 200,000 hours worked for this measure. We exceeded this target.

### *Satisfying our Customers*

In 2014, we approached the objective of customer satisfaction by addressing five measures related to improving customer relations. These measures relate to transmission and distribution customer satisfaction, and connection of new services, as well as estimated bills and no bill volume, as part of our customer service recovery project. Our customer service recovery project was a result of billing issues our company encountered due to the implementation in May 2013 of our new Customer Information System (CIS).

- *Customer Satisfaction – Transmission*
  This measure is to determine the degree to which our transmission customers are satisfied with the service they receive from our company. It is based on survey results of customer surveys conducted on our company's behalf by independent third parties. The survey is given to three major groups of transmission customers. In 2014, we targeted a transmission customer satisfaction rate of 84%. We did not meet this target.

- *Customer Satisfaction – Distribution*
  Similar to the transmission customers, we survey our distribution customers to assess the degree to which they are satisfied with the service they receive from our company. The results arise from surveys conducted on our company's behalf by independent third parties. This measure reflects the overall satisfaction levels of three major distribution customer segments, based on transaction satisfaction levels, annual satisfaction surveys and the meeting of OEB milestones, respectively, for the three segments. For 2014, our company set a target for distribution customer satisfaction at 87%, and did well on the transactional elements, but did not meet this target on an overall basis.

- *Connection of New Customers*
  This measure relates to distribution low-voltage connections that is reported annually to the OEB. It addresses our customers' needs for a specific and timely connection date and assesses our efficiency in connecting new customers. It measures the percentage of connections for a requested new service (< 750 volts). The connection must be completed within five business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and our company. We set a 2014 target of 90%, which we exceeded.

- *Unscheduled Estimated Bills*
  With respect to this measure, we seek to track our company's ability to provide accurate bills to our customers. We track the percentage of total customers that have received unscheduled estimates in any billing period. Our company established a target of 1.8% of all bills for this measure. We exceeded the target.

- *No Bill Volume*
  No bill volume is a customer service measure related to our company's ability to provide timely bills to our customers. This measure tracks the number of customers who have not received a bill in three consecutive billing periods. Our expectation was to reach a volume of 8,000 no-bill customers by September 2014, and sustain this level beyond that date. We exceeded this target.

***Continuous Improvement and Cost-effectiveness***

As part of our strategic objectives to increase productivity through efficiency improvements and effective management of costs, our company measures transmission unit cost and distribution unit cost and sets targets for those costs. Regarding the maintenance and reliability of the transmission and distribution systems, we continue to build and retain public confidence and trust in our company's operations, as stewards of Ontario's electricity grid. In 2014, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for customers in a safe, reliable and efficient fashion. Our company is conscious that commercial customers of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration when interruptions occur. Transmission and distribution reliability is measured through the duration of customer interruptions.

- *Transmission Unit Costs*
  For 2014, the transmission unit cost measure shows the Transmission Business cost-effectiveness by comparing the ratio of operation, maintenance and administration spending to gross fixed asset costs, using benchmarking initiatives. Our company set a target of 2.9% for 2014, and exceeded the target.

- *Distribution Unit Costs*
  Similar to transmission unit cost, the distribution unit cost measure demonstrates the distribution cost-effectiveness by comparing the ratio of operation, maintenance and administration spending to gross fixed asset costs, using benchmarking initiatives. For 2014, our company set a target of 5.7%, but did not meet this target.

- *Customer Interruption Duration – Transmission*
  This measure monitors the reliability of the transmission system by tracking the average length of unplanned interruptions (in minutes) to multiple-circuit supplied delivery points. Our company has set a target of 8.9 minutes per delivery point for 2014. During 2014, our company was aware that we would miss the target, which was not indicative of degrading reliability, but rather a result of refurbishing aging assets. In doing so, this resulted in occasions where load with a multiple-circuit supply was placed on single supply to accommodate the work program. This exposed the system to interruptions if there was a loss of the single supply. Our company determined that it was important to continue with the maintenance program even if this would result in missing the target. Our company, in fact, did not meet this target.

- *Customer Interruption Duration – Distribution*
  This measure is an indicator of the distribution system reliability that expresses the average length of outages in hours that a customer can expect to experience in the year. This measure excludes *force majeure* events and loss of supply events (events caused by the transmission system or other distributors). Our company set a target of 6.7 hours per customer for this measure. In 2014, there were numerous storm events which were not considered *force majeure* events and comparatively more equipment outages that resulted in higher than normal customer interruptions. In the circumstances, we did not meet this target.

***Maintaining a Commercial Culture***

- *Net Income*
  Achievement of strong financial performance is measured by a performance measure of targeted level of net income after tax. Our target was $668 million net income after tax for 2014, and we exceeded our target.
- *Customer Service Recovery Cost*
  As a result of billing issues that arose from the implementation of our new CIS in 2013, the effects of which became acute in early 2014, our company established the customer service recovery project to dedicate staff to resolve outstanding and any new billing issues and stabilize the billing system. We anticipated, and fixed as a target, costs of $48 million (including revenue impacts) for this project. The project was completed in 2014 and the CIS is now in sustainment mode. As the costs of the customer service recovery project exceeded the target, our company did not meet this anticipated target.
- *In-Service Capital – Transmission*
  This new measure for 2014 evaluates how our company is meeting the OEB targets for in-service capital. For our Transmission Business, the 2014 target of 85% of in-service capital to our business plan is based on historical performance, our increasing capital work program, and the additional variability caused by external commitments and required approvals. Our 2014 result shows that our company exceeded the target.
- *In-Service Capital – Distribution*
  For our Distribution Business, our company set the 2014 target of 87% of in-service capital to our business plan based on historical performance, with adjustments to reflect that our Distribution Business has more storm-related capital spending than our Transmission Business, as well as the performance of our smart meter and distributed generation capital work programs. Our 2014 result was better than the target.

## REGULATION

Our Transmission and Distribution Businesses are primarily regulated by the OEB and the National Energy Board (NEB).

### Provincial Framework

The *Electricity Act, 1998*, and the *OEB Act* primarily establish the broad legislative framework for Ontario's electricity market. The *Electricity Act, 1998*, sets out the fundamental principles of Ontario's electricity industry, enabling open and nondiscriminatory access to transmission and distribution systems. The *OEB Act* provides the OEB with the jurisdiction and mandate to regulate Ontario's electricity market. The OEB provides a framework for the review of electrical utilities' distribution and transmission revenue requirements so that rates may be established based on historical average or forecasted needs.

The OEB approves both the revenue requirements of and the rates charged by our regulated businesses. The rates are designed to permit our businesses to recover the allowed costs and to earn a formula-based annual rate of return on our common equity 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 accounts over specified timeframes.

The OEB 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 (IFRS) beginning on January 1, 2015.

### *Renewed Regulatory Framework*

In December 2010, the OEB initiated a coordinated consultation process for the development of a Renewed Regulatory Framework for Electricity (RRFE). In October 2012, the OEB issued its report *A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach*. The report identified three rate-setting models available to provide choices suitable for distributors having varying capital requirements: a fourth-generation Incentive Regulation Mechanism (IRM); a custom rate setting; and an Annual Incentive Rate-setting Index method. The report also provided information on performance measurement, continuous improvement and implementation of the new framework.

In late 2013, the OEB issued its *Report of the Board on Rate-Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. This report sets out the OEB's policies and approaches to the rate adjustment parameters for incentive rate setting for electricity distributors and the benchmarking of electricity distributor total cost performance. It also includes the OEB's determination on rate adjustment parameter values for 2014 incentive rate setting, which were used to adjust Hydro One Networks' 2014 distribution rates.

## Federal Framework

While most electricity power lines and facilities in Canada fall within provincial jurisdiction, the NEB has jurisdiction over the construction and operation of international power lines (IPLs). Hydro One Networks owns and operates IPLs with New York, Michigan and Minnesota, and is subject to several NEB-issued certificates and permits. According to the *NEB Act*, any modifications to an IPL require NEB approval.

In 2012, the NEB issued a general order and five amending orders for mandatory electricity reliability standards for certain IPLs in Canada. The orders (i) require Hydro One Networks, as the owner of such lines, to comply with specified North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC) reliability standards, (ii) mandate certain reporting requirements, and (iii) contain provisions for IPL owners to seek exemptions. In March 2013, Hydro One Networks submitted to the NEB a declaration of compliance and a request for indefinite exemptions from a list of standards that do not apply to Hydro One Networks or to the IPLs it owns. On November 13, 2013, the NEB granted Hydro One Networks' exemption requests, with some minor exceptions. Hydro One Networks maintains compliance with all applicable NEB orders and seeks approval for all appropriate exemptions, as required.

NERC Critical Infrastructure Protection (Cyber Security) standards are designed to ensure that utilities and other users, owners, and operators of the bulk power system in North America have appropriate procedures in place to protect critical infrastructure from cyber attack. As a result, our physical, electronic and information security processes have been upgraded to meet more stringent security requirements in order to meet NERC's requirements. The NERC Cyber Security standards were updated and revised in 2013, resulting in additional work, effort and associated costs for our company. We anticipate these costs will be spread over a number of years, and expect that they will be recovered in future rates.

## Regulatory Proceedings

The following table summarizes our company's recent major regulatory proceedings:

| Application | Year(s) | Type | Date Filed | Current Status |
|---|---|---|---|---|
| **Electricity Rates – Transmission Rate Applications** | | | | |
| Hydro One Networks | 2013–2014 | Cost-of-service | May 28, 2012 | OEB decision received on January 9, 2014[1] |
| Hydro One Networks | 2015–2016 | Cost-of-service | September 16, 2014 | OEB decision received on December 2, 2014 |
| B2M LP | 2015 | Interim | October 24, 2014 | OEB decision received on December 11, 2014 |
| **Electricity Rates – Distribution Rate Applications** | | | | |
| Hydro One Networks | 2014 | IRM | April 26, 2013 | OEB decision received December 5, 2013 |
| Hydro One Networks | 2015–2019 | Custom | December 19, 2013 | OEB decision anticipated in 2015 Q1 |
| Hydro One Brampton Networks | 2014 | IRM | August 14, 2013 | OEB decision received December 5, 2013 |
| Hydro One Brampton Networks | 2015 | Cost-of-service | April 23, 2014 | OEB decision received on January 15, 2015 |
| Hydro One Remote Communities | 2014 | IRM | October 25, 2013 | OEB decision received March 13, 2014 |
| Hydro One Remote Communities | 2015 | IRM | September 24, 2014 | OEB decision anticipated in 2015 Q1 |
| **Mergers Acquisitions Amalgamations and Divestitures (MAAD) Applications** | | | | |
| Norfolk Power | n/a | Acquisition | April 26, 2013 | OEB decision received July 3, 2014 |
| Woodstock Hydro | n/a | Acquisition | July 9, 2014 | OEB decision anticipated in 2015 |
| Haldimand Hydro | n/a | Acquisition | July 31, 2014 | OEB decision anticipated in 2015 |
| **Leave to Construct Application** | | | | |
| Supply to Essex County Transmission Reinforcement Project | n/a | Section 92 | January 22, 2014 | OEB decision anticipated in 2015 |

[1] OEB Oral Decision for 2013 transmission rates was received on November 8, 2012. On December 6, 2013, we submitted a draft Rate Order for our 2014 transmission rates. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed.

### *Electricity Rates*

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP). The RPP regulates the commodity price of electricity only and does not affect the rates charged for transmission and distribution of electricity. The OEB sets prices for RPP customers based on both a two-tiered electricity pricing structure with seasonal consumption thresholds, and a three-tiered electricity pricing structure with Time-of-Use (TOU) thresholds. New RPP prices are computed at six-month intervals and are the result of an integrated consideration of rebasing and true-ups. The following is a summary of the two-tiered RPP and the TOU RPP prices for the reporting and comparative periods:

| RPP | Tier Threshold (kWh/month) | | Tier Rates (cents/kWh) | |
|---|---|---|---|---|
| **Effective Date** | **Residential** | **Non-Residential** | **Lower Tier 1** | **Upper Tier 2** |
| November 1, 2012 | 1,000 | 750 | 7.4 | 8.7 |
| May 1, 2013 | 600 | 750 | 7.8 | 9.1 |
| November 1, 2013 | 1,000 | 750 | 8.3 | 9.7 |
| May 1, 2014 | 600 | 750 | 8.6 | 10.1 |
| November 1, 2014 | 1,000 | 750 | 8.8 | 10.3 |

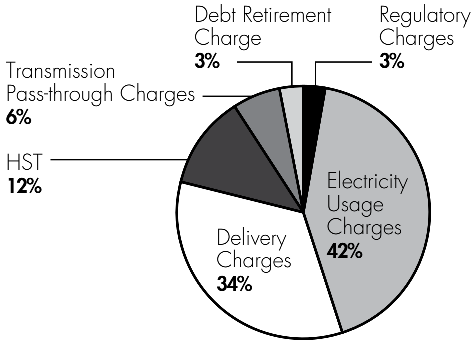
| TOU RPP | Rates (cents/kWh) | | |
|---|---|---|---|
| **Effective Date** | **On Peak** | **Mid Peak** | **Off Peak** |
| November 1, 2012 | 11.8 | 9.9 | 6.3 |
| May 1, 2013 | 12.4 | 10.4 | 6.7 |
| November 1, 2013 | 12.9 | 10.9 | 7.2 |
| May 1, 2014 | 13.5 | 11.2 | 7.5 |
| November 1, 2014 | 14.0 | 11.4 | 7.7 |

In 2010, the OEB issued its final determination to mandate TOU pricing for RPP customers. All eligible Hydro One distribution customers were migrated to TOU billing as of June 2011, except certain customers located in very rural and very sparsely populated areas. An exemption from the requirement to move these customers to TOU pricing was approved until December 31, 2014. On December 1, 2014, Hydro One filed a request with the OEB for a five-year exemption extension for 120,000 hard-to-reach customers and requested permission to migrate an additional 50,000 customers back to two-tiered RPP pricing, as it is not economically feasible to consistently provide actual readings from these meters. An OEB Hearing on this matter has commenced. The OEB issued an interim Decision granting an exemption extension until June 30, 2015 or until a final OEB Decision is issued.

Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators by the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998*. The IESO is responsible for overseeing and operating the wholesale electricity market, as well as ensuring the reliability of the integrated power system.

A typical residential customer consumes 800 kWh of electricity per month. The total bill for a typical residential customer consists of the following: electricity usage charges based on RPP rates; electricity delivery charges based on OEB-approved distribution rates; transmission pass-through charges for the usage of the transmission system; regulatory charges, which include wholesale market costs and rural and remote rate protection amounts; the debt retirement charge; and the harmonized sales tax (HST).

**Composition of Total Bill for Typical Residential Customer**




***Transmission Rates***

Our transmission revenues primarily include our transmission tariff, which is based on the province-wide Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario. The OEB rate-setting process is a rigorous judicial process based on evidence, and usually legal cross-examination of witnesses who testify to the volumes of information submitted. The transmission tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on our common equity.

- **Hydro One Networks**

  In May 2012, we filed a cost-of-service rate application with the OEB for our 2013 and 2014 transmission rates. The application sought OEB approval for revenue requirement increases of approximately 0.6% in 2013 and 9.1% in 2014, or estimated increases of 0% in 2013 and 0.7% in 2014 on a typical residential customer's total bill. In November 2012, we submitted a draft Rate Order, which included revenue requirements of approximately $1,438 million and $1,528 million for 2013 and 2014, respectively. For a typical residential customer, this represents no change from the 2012 OEB-approved rate levels in 2013 and a 5.8% increase in 2014 for the transmission portion of the bill, or no change for 2013 and an increase of 0.5% for 2014 when considering total bill impact. In December 2012, the OEB approved the 2013 and 2014 transmission revenue requirements as requested. The 2013 Ontario UTRs remained unchanged at the 2012 levels.

On December 6, 2013, we submitted a draft Rate Order for our 2014 transmission rates. The 2014 revenue requirement 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. For a typical residential customer, this represents an increase of 6.3% in 2014 for the transmission portion of the bill, or 0.5% when considering total bill impact.

On September 16, 2014, Hydro One Networks filed its application, evidence and Settlement Agreement with the OEB in support of proposed transmission revenue requirements to be implemented on January 1, 2015 and January 1, 2016. This application is pursuant to a comprehensive Settlement Agreement between the stakeholders and Hydro One Networks. On January 8, 2015, the OEB approved the Hydro One transmission rates revenue requirement, excluding the B2M LP revenue requirement, for 2015 of $1,477 million and the 2016 revenue requirement of $1,516 million, subject to adjustments for the cost of capital parameters. For a typical residential customer, this represents increases of 0.4% in 2015 and 1.4% in 2016 for the transmission portion of the bill, or increases of 0.03% in 2015 and 0.1% in 2016 when considering total bill impact.

- **B2M LP**

  On October 24, 2014, B2M LP filed an application with the OEB for an interim transmission rate, effective January 1, 2015, seeking approval for a revenue requirement of $41 million in 2015. This rate is equal to the amount included in Hydro One Networks' transmission rates for the Bruce to Milton Line assets, resulting in no change to overall UTRs. The interim Rate Order was approved by the OEB on December 11, 2014. B2M LP was directed to file a full cost-of-service application for final 2015 transmission rates by April 1, 2015.

  A full discussion of the B2M LP transaction can be found in the section "New Developments in 2014 – Business Combinations."

***Distribution Rates***

Our distribution revenues primarily include our distribution tariff, which is based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. The distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on our common equity.

- **Hydro One Networks**

  In June 2012, Hydro One Networks filed an IRM application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued a final Rate Order, 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.

  On April 26, 2013, Hydro One Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. On September 26, 2013, the OEB issued a partial Decision, approving a rate rider to recover a 2014 revenue requirement of $29 million for operation, maintenance and administration expenses and in-service capital costs of the ADS Project, which will modernize our distribution system. On December 5, 2013, the OEB issued its final Decision, which resulted in an increase of distribution rates of approximately 2.4% in 2014, or 0.85% when considering total bill impact, for a typical residential customer.

  On December 19, 2013, Hydro One Networks filed a 2015–2019 distribution custom rate application with the OEB, for rates effective January 1 of each test year. This application is a five-year custom rate application submitted under the OEB's RRFE, and has been customized to fit Hydro One Networks' specific circumstances, which necessitate significant multi-year investments. We are seeking OEB approval for distribution revenue requirements of $1,415 million for 2015, $1,523 million for 2016, $1,578 million for 2017, $1,615 million for 2018, and $1,660 million for 2019. If the application is approved as filed, the resulting change to the distribution portion of the bill for a typical residential customer will be approximately a 1.4% decrease in 2015, 3.8% increase in 2016, 2.3% increase in 2017, 1.2% increase in 2018, and 2.6% increase in 2019. When considering total bill impact, the resulting change will be approximately a 1.5% decrease in 2015, 1.3% increase in 2016, 0.8% increase in 2017, 0.4% increase in 2018, and 0.9% increase in 2019 for a typical residential customer. A technical conference, a settlement conference and an Oral Hearing took place in the third quarter of 2014. On December 18, 2014, the OEB issued a Decision and interim Rate Order approving the 2014 distribution rates as interim 2015 rates effective January 1, 2015. The OEB also approved the discontinuation of the collection of revenues for the provincially funded portion of renewable generation connection investments of approximately $20 million per year from ratepayers effective December 31, 2014. A final Decision and Order from the OEB is anticipated in the first quarter of 2015.

- **Hydro One Brampton Networks**

  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 released a Decision that resulted in an increase in distribution rates of approximately 0.3% for 2013, or less than 0.1% on the average total bill for a typical residential customer.

  In August 2013, Hydro One Brampton Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. On December 5, 2013, the OEB released a Decision that resulted in a reduction in distribution rates of approximately 2.3% for 2014, or a 0.5% reduction on the average total bill for a typical residential customer.

  On April 23, 2014, Hydro One Brampton Networks filed a cost-of-service application with the OEB for 2015 distribution rates, to be effective January 1, 2015, after being in an IRM application period for three years. The 2015 distribution rate application was seeking the approval of a revenue requirement of approximately $74 million for 2015. In its application, Hydro One Brampton Networks also requested OEB approval for retail transmission service rates and the approval of rate riders to dispose of certain deferral and variance accounts. A partial Settlement Proposal was filed with the OEB and the unsettled issues were heard by the OEB in an Oral Hearing in October 2014. On December 18, 2014, the OEB approved a revenue requirement of $72 million. The reduction of $2 million is mainly attributable to updates to the cost of capital parameters, operation, maintenance and administration, and depreciation expense. For a typical residential customer, this represents an increase of 4.5% in 2015 for the distribution portion of the bill, or 1.6% when considering total bill impact. The increase is reflective of increased rate base and higher operation, maintenance and administration costs since Hydro One Brampton Networks' last cost-of-service application in 2011. On January 15, 2015, the OEB issued its final Rate Order approving the application.

- **Hydro One Remote Communities**

  In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 distribution rates, seeking approval for a 2013 revenue requirement of $53 million. In August 2013, the OEB issued a final Decision approving a revenue requirement of $51 million and rate increase of approximately 3.45%, with an effective date of May 1, 2013.

  In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 distribution rates, seeking approval for a rate increase of approximately 0.48%. On March 13, 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.

  On September 24, 2014, Hydro One Remote Communities filed an IRM application with the OEB for 2015 rates, seeking approval for increased base rates for the distribution and generation of electricity of 1.7% to be effective May 1, 2015. A final Decision from the OEB is anticipated in the first quarter of 2015.

### *Mergers Acquisitions Amalgamations and Divestitures (MAAD) Applications*

*Norfolk Power Acquisition*

On April 26, 2013, Hydro One filed a MAAD application with the OEB for the approval of the acquisition of Norfolk Power. On July 3, 2014, the OEB issued its Decision and Order granting Hydro One leave to acquire all of the issued and outstanding common shares of Norfolk Power within 18 months from the date of this Decision and Order. In addition, among other items, the OEB's Decision and Order granted Norfolk Power Distribution Inc. (NPDI), a subsidiary of Norfolk Power, leave to transfer its distribution system to Hydro One Networks within 18 months from the date of this Decision and Order, and ordered that NPDI file with the OEB a draft Rate Order that includes a proposed Tariff of Rates and Changes reflecting the OEB's approval of a 1% reduction relative to NPDI's 2012 base electricity delivery rates. As part of the Norfolk Power acquisition agreement, Norfolk Power residential customers received a 1.4% reduction to their monthly distribution delivery rates, and general service customers received a reduction of between 1.4% and 1.6%, depending on their rate class, effective September 8, 2014. In addition, Norfolk Power customers' distribution rates will be frozen for the next five years. Once the NPDI distribution system transfer is completed, the OEB will transfer NPDI's electricity distribution licence and NPDI's Rate Order to Hydro One Networks. A full discussion of the Norfolk Power acquisition can be found in the section "New Developments in 2014 – Business Combinations."

*Woodstock Hydro Acquisition*

On July 9, 2014, Hydro One filed a MAAD application with the OEB for the approval of the acquisition of Woodstock Hydro, which is anticipated to be completed in 2015. A full discussion of the Woodstock Hydro acquisition can be found in the section "New Developments in 2014 – Business Combinations."

*Haldimand Hydro Acquisition*

On July 31, 2014, Hydro One filed a MAAD application with the OEB for the approval of the acquisition of Haldimand Hydro, which is anticipated to be completed in 2015. A full discussion of the Haldimand Hydro acquisition can be found in the section "New Developments in 2014 – Business Combinations."

***Leave to Construct Application***

*Supply to Essex County Transmission Reinforcement Project*

On January 22, 2014, Hydro One Networks submitted a Leave to Construct application to the OEB under Section 92 of the *OEB Act* to construct a new 13-kilometre 230 kV double-circuit transmission line in the Windsor-Essex region. The new transmission line will connect to a proposed transmission station in the Municipality of Leamington and an existing 230 kV transmission line between Chatham and Windsor. Further discussion of the Supply to Essex County Transmission Reinforcement Project can be found in the section "Liquidity and Capital Resources – Investing Activities – Major Transmission Projects."

## Contractual Agreements, Codes and Licences

As a regulated company, we are subject to various contractual arrangements, codes and licences.

***Operating Agreement with the IESO***

The IESO is the system controller of Ontario's electricity system. The IESO manages the reliability of Ontario's power system, forecasts the demand and supply of electricity and co-ordinates emergency preparedness for Ontario's electricity system. The IESO also operates the wholesale electricity market, while ensuring fair competition through market surveillance.

Under the *Electricity Act, 1998*, the IESO is required to enter into agreements with transmitters, giving it the authority to direct the operations of the transmitters' systems. Our operating agreement with the IESO, which sets out the specific responsibilities of both parties relating to the provision of transmission service, extends until December 31, 2019. The distribution portion of Ontario's network is not directed by the IESO and remains subject to the operational control of LDCs in accordance with the regulatory framework.

***Hydro One's Relationships with Other Market Participants***

Generators, LDCs and customers directly connected to our transmission system must enter into agreements with us to ensure reliable connection service in conformity with the Transmission System Code (TSC) established by the OEB.

Some market participants, such as generators and large load customers embedded within distribution systems, are supplied from the wholesale market through lines and facilities that are defined or deemed by the OEB as "distribution" and owned by LDCs. At a minimum, under the *Electricity Act, 1998*, LDCs must provide nondiscriminatory access for eligible generators and customers to the wholesale markets administered by the IESO.

***Electricity Industry Codes***

The OEB has issued and revised several codes that govern the operation of OEB-licensed entities in Ontario. These codes include, but are not limited to, the Affiliate Relationships Code for Electricity Distributors and Transmitters, the Standard Supply Service Code, the TSC, the Distribution System Code (DSC), the Retail Settlement Code, the Electricity Retailer Code of Conduct, the Smart Sub-Metering Code, and the Conservation and Demand Management (CDM) Code. These codes prescribe minimum standards of conduct and standards of service for transmitters, distributors, smart sub-metering providers and/or retailers in the electricity market.

***Electricity Industry Licences***

Our transmission and distribution licences were issued in 2003 and 2004, respectively. The licences for all of our regulated businesses have a 20-year term and incorporate reporting and record-keeping requirements in accordance with the OEB's Electricity Reporting and Record Keeping Requirements. Further discussion of the OEB's Electricity Reporting and Record Keeping Requirements can be found in the section "Regulation – Regulatory Developments – Performance Measurement and Continuous Improvement." Our licences promote the expansion and upgrading of the transmission and distribution systems to accommodate load due to forecasted demand growth over the long term, the connection of renewable energy generation facilities, and implementation of modern technologies to improve reliability, operations and network planning.

## Regulatory Developments

### *Long-Term Energy Plan*

On December 2, 2013, the Province released its updated Long-Term Energy Plan (2013 LTEP), *Achieving Balance*, replacing the 2010 LTEP. The 2013 LTEP sets out the Province's plan of action for the energy sector, including strategies for mitigating increases in electricity rates; continued renewable energy procurement; nuclear refurbishment; enhanced regional planning with respect to energy infrastructure; transmission enhancements; encouraging Aboriginal participation in energy development, transmission and conservation projects; and the expansion of natural gas infrastructure. The plans are guided by the goal of balancing five core principles: cost-effectiveness, reliability, clean energy, community engagement, and CDM. Pursuant to the 2013 LTEP, the Province "will encourage Ontario Power Generation Inc. (OPG) and Hydro One to explore new business lines and opportunities inside and outside Ontario. These opportunities will help leverage existing areas of expertise and grow revenues for the benefit of Ontarians." We will continue to work with the Province to develop business plans and efficiency targets that will reduce costs and result in significant ratepayer savings. The 2013 LTEP encourages conservation and reinforces the policy of considering conservation first in planning processes. Under the 2013 LTEP, conservation will be used to lessen the need for new supply-and-demand response initiatives to meet peak demand requirements.

### *Procurement of New Generation*

The Ontario Power Authority's (OPA) Feed-in Tariff (FIT) Program is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy, and water power up to 50 MW. The FIT program is currently divided into three streams: MicroFIT (projects up to 10 kW), Small FIT (projects between 10 kW and 500 kW), and regular FIT (projects greater than 500 kW), all of which may result in connections to our distribution system. Under the FIT program, the OPA has entered into contracts or conditional contracts with generation proponents pursuant to which the OPA will pay a fixed rate for power produced over a specified period of time. We continue to connect projects for which there are firm contracts.

On May 30, 2013, the Province announced that it would make 900 MW of new capacity available between 2013 and 2018 for the Small FIT and MicroFIT programs. The Province has set annual procurement targets, from 2014 onwards, of 150 MW for Small FIT generation and 50 MW for MicroFIT generation. The Province is working with the OPA to develop a competitive process for renewable energy generation projects above 500 kW. The new process will replace the existing large project stream of the FIT program. As at December 31, 2014, our company has connected more than 560 FIT and nearly 12,000 MicroFIT projects, enough energy to power approximately 274,000 homes. These connections represent over 1,000 MW of power.

### *Conservation and Demand Management*

The OEB's CDM guidelines for electricity distributors provide guidance on certain provisions in the CDM Code and the type of evidence that should be filed by distributors in support of applications for OEB-approved CDM programs. The guidelines also provide details on the Lost Revenue Adjustment Mechanism (LRAM) related to CDM programs implemented under the CDM Code. LRAM is the mechanism by which LDCs are compensated for lost revenues associated with their respective load reductions resulting from CDM programs. In addition, the guidelines state that savings associated with TOU pricing are eligible to be counted towards the 2011–2014 CDM targets. The funding for the OPA-contracted Ontario-wide CDM programs is in place until December 31, 2015. This will provide an opportunity for the OPA and LDCs to work collaboratively to strengthen the current framework, and to keep customer programs in place for 2015.

On September 30, 2014, in accordance with the CDM Code, Hydro One Networks and Hydro One Brampton Networks each filed a 2013 Annual CDM Report with the OEB outlining CDM activities, energy and peak demand savings results achieved in 2013, and expectations regarding CDM targets for 2014. Hydro One Networks reported that it expected to reach 95% to 100% of its demand target and 80% of its cumulative energy target by the end of 2014. Hydro One Brampton Networks reported that it expected to reach 60% of its demand target and 100% of its cumulative energy target by the end of 2014.

In March 2014, the Minister of Energy issued parallel directives to the OEB and the OPA, respectively, regarding the new "2015–2020 Conservation Framework." The directives call for the OPA to establish a provincial target of 7 TWh of persistent energy savings to be achieved by 2020 and for all LDCs to enter into an Electricity Conservation Agreement with the OPA by December 31, 2014. Both Hydro One Networks and Hydro One Brampton Networks submitted their signed Electricity Conservation Agreements to the OPA in December 2014. Conservation opportunities will be provided to customers and available to distributors to ensure both end-user usage and utility systems are as efficient as possible.

The OPA allocated targets and budgets to LDCs on October 31, 2014. Hydro One Networks' 2015–2020 CDM savings target is 1,159 GWh, to be achieved with a budget of approximately $322 million. Hydro One Brampton Networks' 2015–2020 CDM savings target is 255.2 GWh, to be achieved with a budget of approximately $67 million. All LDCs must submit CDM Plans indicating how they will achieve their allocated targets by May 1, 2015 using either "Full Cost Recovery" or "Pay-for-Performance" funding models. All CDM programs must be cost-effective to ensure full cost recovery. LDCs may, at any point, resubmit changes to their CDM Plan for approval by the OPA.

On December 19, 2014, the OEB issued its new CDM Guidelines (2015 Guidelines). The 2015 Guidelines are consistent with the Directive the OEB received in March 2014 from the Minister of Energy requiring the OEB to take steps to promote CDM, including amendments to the licences of electricity distributors and the establishment of CDM Requirement guidelines.

***Revenue Decoupling for Distributors***

In November 2012, the OEB initiated a project to coordinate revenue decoupling with the new rate-setting policies proposed in the RRFE. On April 3, 2014, the OEB released a Draft Report of the Board on Rate Design for Electricity Distributors (Rate Design Report) to solicit stakeholder comments. The Rate Design Report presents three proposals to achieve revenue decoupling: (1) a single monthly charge which is the same for all consumers within the rate class; (2) a fixed monthly charge, with the size of the charge to be based on the size of the electrical connection; and (3) a fixed monthly charge where the size of the charge is based on use during peak hours. The OEB expects to issue a report in early 2015 regarding the phase-in implementation of fixed rates.

***Performance Measurement and Continuous Improvement***

On March 5, 2014, the OEB issued its *Report of the Board on Performance Measurement for Electricity Distributors: A Scorecard Approach* (Performance Report) under its RRFE. The Performance Report sets out the OEB's policies on the measures that will be used by the OEB to assess a distributor's effectiveness and improvement in achieving customer focus, operational effectiveness, public policy responsiveness, and financial performance to the benefit of existing and future customers, as well as the form and implementation of a performance monitoring tool – a Scorecard.

On July 15, 2014, the OEB issued a Staff Discussion Paper "Electricity Distribution System Reliability Measures and Targets" to establish specific performance targets for the existing system reliability measures, to develop customer-specific reliability measures and to address the monitoring of momentary outages.

***Regional Plans***

In August 2013, the OEB amended the TSC and DSC to implement a more formal and structured approach to regional planning in Ontario. The new regional planning approach consists of two main processes: Regional Infrastructure Planning (RIP) to be led by transmitters, and Integrated Regional Resource Planning (IRRP) to be led by the OPA. The RIP process focuses mainly on wires planning, both transmission and distribution, and the IRRP process focuses on resources planning (e.g. generation, CDM) and the integration of resources with wires planning. The development of regional plans will involve close coordination of the two processes and active participation by the OPA, transmitters, distributors and other applicable agencies such as the IESO.

The regional plans are intended to support investments brought forward in transmitter and distributor rate submissions and transmitter Leave to Construct applications. Regional plans are to be reviewed or developed at least every five years. The OEB expects the first cycle of regional plans for all regions in Ontario to be completed in the next three to four years. For regional planning purposes, the province has been subdivided into 21 regions. Hydro One is the lead transmitter responsible for the RIP process for 19 of the 21 regions. Planning activities are underway and the regional plans are expected to be completed between 2015 and 2017.

## NEW DEVELOPMENTS IN 2014

### Premier's Advisory Council on Government Assets

On April 11, 2014, the Province announced the appointment of the Premier's Advisory Council on Government Assets (Council) to provide the Province with recommendations designed to maximize the value of certain provincially owned assets, one of which being our company. The objective of the review is to advise the Province on how to best maximize value from its assets. The Council's Terms of Reference provided guidance indicating that it would give preference to continued ownership of government assets, but would consider mergers, acquisitions, divestments if there is a strong business case, and would enhance value to taxpayers of the Province.

The interim report released on November 19, 2014, noted our company's Transmission Business is a well-run entity with some opportunities to deliver savings on the operating side and on capital expenditures, and recommended that the Province maintain its ownership of our company's Transmission Business. The interim report noted that Ontario's local electricity distribution system is an unnecessarily cluttered and fragmented system with too many entities, some of which are highly inefficient, unable to adapt to the changing environment and lack capital to modernize or consolidate.

Consequently, the Council recommended that our company's Transmission and Distribution Businesses be separated, and that Hydro One Networks' distribution business and Hydro One Brampton Networks be used to spur industry consolidation. The Council also recommended that the Province reduce its equity interest in our company's Distribution Business by bringing in private sector investment.

The Province has now asked the Council to build on its work by entering phase two, which includes the Council receiving and discussing written ideas related to encouraging consolidation and to Hydro One Brampton Networks and Hydro One Networks' distribution business, and finalizing its recommendations to the Province. We understand that the Province is specifically considering the sale of Hydro One Brampton Networks, as well as the distribution business of Hydro One Networks.

**Business Combinations**

***B2M LP***

In 2012, we entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively referred to as the SON, where a noncontrolling equity interest in 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 our 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 our 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. B2M LP is now operational.

Details of B2M LP's transmission rate application can be found in the section "Regulation – Regulatory Proceedings – Transmission Rates."

***Norfolk Power Acquisition***

On August 29, 2014, our company completed the acquisition of the outstanding shares of Norfolk Power from The Corporation of Norfolk County. Norfolk Power is a holding company that owns NPDI, a local electricity distribution company, and Norfolk Energy Inc., a non-rate regulated energy services company, located in southwestern Ontario. The selection of our company as successful bidder followed a comprehensive, competitive sales process initiated by Norfolk Power.

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 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. We have also determined the preliminary purchase price adjustments based on agreed working capital and other balances at the acquisition date. The resulting preliminary 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. We intend to complete the determination of the final purchase price adjustments during the first half of 2015.

Norfolk Power contributed revenues of $18 million and net income of less than $1 million to our company's consolidated financial results for the year ended December 31, 2014.

Details of the Norfolk Power MAAD application can be found in the section "Regulation – Regulatory Proceedings – MAAD Applications."

***Woodstock Hydro Purchase Agreement***

On May 21, 2014, we reached an agreement with the City of Woodstock to acquire 100% of the common shares of Woodstock Hydro for approximately $29 million, subject to final closing adjustments. Woodstock Hydro is an urban electricity distribution company located in southwestern Ontario. The transaction is the result of extensive discussions between Hydro One and the City of Woodstock which involved consideration of economic development opportunities and other benefits resulting from the sale of Woodstock Hydro. The acquisition is pending a regulatory decision from the OEB and is anticipated to be completed in 2015.

Details of the Woodstock Hydro MAAD application can be found in the section "Regulation – Regulatory Proceedings – MAAD Applications."

***Haldimand Hydro Purchase Agreement***

On June 10, 2014, we reached an agreement with Haldimand County to acquire 100% of the common shares of Haldimand Hydro for approximately $65 million, subject to final closing adjustments. Haldimand Hydro is an electricity distribution and telecom company located in southwestern Ontario. The transaction is the result of extensive discussions between Hydro One and Haldimand County. The acquisition is pending a regulatory decision from the OEB and is anticipated to be completed in 2015.

Details of the Haldimand Hydro MAAD application can be found in the section "Regulation – Regulatory Proceedings – MAAD Applications."

**Other**

***Environment Canada Regulations***

In April 2014, Environment Canada issued Canada Gazette II, which included amendments to the existing polychlorinated biphenyl (PCB) regulations, including the extension of the end-of-use deadline beyond 2014 for equipment containing certain concentrations of PCBs, with an effective date of January 1, 2015. The amendments extend the end-of-use deadline for our company's PCBs in concentrations of 500 parts per million or more from December 31, 2014 to December 31, 2025. As a result of an annual review of environmental liabilities, our company recorded a revaluation adjustment in 2014 to reduce our environmental liabilities by $20 million. This adjustment included the impact of the PCB regulations amendments.

***Electricity Sector Pension Plans***

On August 1, 2014, a Report on the Sustainability of Electricity Sector Pension Plans (Sustainability Report) was released by Jim Leech, Special Advisor to the Minister of Finance for Ontario. As part of its fiscal 2013 budget, the Province announced its intention to establish a government-led industry Working Group (Working Group) to address pension issues associated with the single-employer pension plans at Hydro One, OPG, IESO and the Electrical Safety Authority (ESA). This Sustainability Report is intended to inform and help frame the efforts of the Working Group. The Sustainability Report noted that it is critically important for any pension plan for public-sector workers to be sustainable so that the retirement income of retirees and active members is secure. Management will continue to monitor the initiatives of this Working Group and potential impacts of any recommendations for Hydro One accordingly. To ensure the sustainability of the Hydro One Pension Plan, our company has implemented a gradual increase in the amount of employee contributions to the plan.

***Outsourcing Agreements***

The current agreement with Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., expires on February 28, 2015. On November 28, 2014, we 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 us 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, we reached agreement with Inergi to provide us with second-generation customer service operations outsourcing services for a fixed period of three years beginning March 1, 2015 to February 28, 2018.

In its re-tendering initiative, Hydro One set out four objectives for its new outsourcing agreements: continually improved value for money; providing operational flexibility; delivery of services to reflect global best practices; and robust, effective performance management and governance. This agreement achieves those objectives and supports our company's key strategic objectives, while allowing the Company to focus on its core activities of maintaining, planning and operating our Transmission and Distribution Businesses and delivering excellent service to our customers. The agreement will see cost savings on annual base fees while at the same time providing service delivery improvements, as we continue our ongoing efforts to reduce costs and drive more efficiency in our business.

In September 2014, we entered into an agreement with Brookfield Johnson Controls Canada LP (Brookfield), a service provider selected through a competitive procurement process, for facilities management services for a term of ten years, effective January 1, 2015 to December 31, 2024, with the option to renew for an additional term of three years. Over the term of the contract we will transition the facilities management of all of our facilities. Under the agreement, Brookfield will provide us with facilities management and execution of certain capital projects as deemed required by our 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 our company, with no minimum capital work guarantee.

Details of our contractual obligations under our outsourcing agreements can be found in the section "Liquidity and Capital Resources – Summary of Contractual Obligations and Other Commercial Commitments."

## ANNUAL RESULTS OF OPERATIONS

| *Year ended December 31 (millions of Canadian dollars)* | **2014** | 2013 | $ Change | % Change |
|---|---|---|---|---|
| Revenues | **6,548** | 6,074 | 474 | 8 |
| Purchased power | **3,419** | 3,020 | 399 | 13 |
| Operation, maintenance and administration | **1,192** | 1,106 | 86 | 8 |
| Depreciation and amortization | **722** | 676 | 46 | 7 |
| | **5,333** | 4,802 | 531 | 11 |
| **Income before financing charges and provision for payments in lieu of corporate income taxes** | **1,215** | 1,272 | (57) | (4) |
| Financing charges | **379** | 360 | 19 | 5 |
| **Income before provision for payments in lieu of corporate income taxes** | **836** | 912 | (76) | (8) |
| Provision for payments in lieu of corporate income taxes | **89** | 109 | (20) | (18) |
| **Net income** | **747** | 803 | (56) | (7) |
| Net income (loss) attributable to noncontrolling interest | **(2)** | – | (2) | (100) |
| **Net income attributable to Shareholder of Hydro One** | **749** | 803 | (54) | (7) |

### Revenues

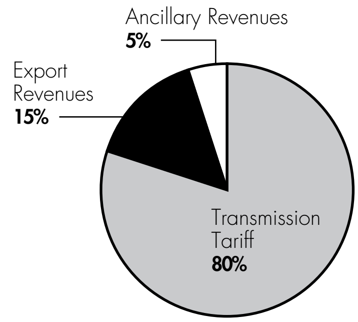
| *Year ended December 31 (millions of Canadian dollars)* | **2014** | 2013 | $ Change | % Change |
|---|---|---|---|---|
| Transmission | **1,588** | 1,529 | 59 | 4 |
| Distribution | **4,903** | 4,484 | 419 | 9 |
| Other | **57** | 61 | (4) | (7) |
| | **6,548** | 6,074 | 474 | 8 |
| Average annual Ontario 60-minute peak demand (MW)[1] | **20,596** | 21,493 | (897) | (4) |
| Distribution – units distributed to our customers (TWh)[1] | **29.8** | 29.8 | – | – |

[1] System-related statistics are preliminary.

### *Transmission*

Transmission revenues primarily consist of our transmission tariff, which is based on the monthly peak electricity demand across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets, ancillary revenues primarily attributable to maintenance services provided to generators, and secondary use of our land rights.

**Composition of 2014 Transmission Revenues**



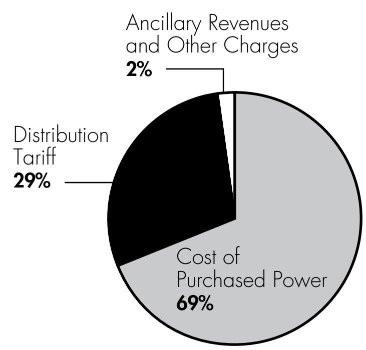

Our 2014 transmission revenues increased by $59 million, or 4%, compared to 2013. The components of the increase include the following:

- $90 million increase due to new transmission rates effective January 1, 2014 approved by the OEB in January 2014; Ê
- $42 million increase due to the OEB's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions and the disposition of certain OEB-approved transmission regulatory accounts;
- $45 million decrease due to lower average Ontario 60-minute peak demand in 2014. The lower electricity demand in 2014 was mainly due to milder weather in the summer and fall of 2014, compared to 2013; and
- $28 million decrease due to ancillary transmission revenues, primarily associated with OEB-approved regulatory accounts.

### *Distribution*

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our Distribution Business. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include minor ancillary distribution service revenues, such as fees related to the joint use of our distribution poles by the telecommunications and cable television industries, as well as miscellaneous charges such as charges for late payments.

**Composition of 2014 Distribution Revenues**




Our 2014 distribution revenues increased by $419 million, or 9%, compared to 2013. The components of the increase include the following:

- $399 million increase due to the recovery of higher purchased power costs, as described below under "Purchased Power;" Ê
- $12 million increase due to new distribution rates effective January 1, 2014 approved by the OEB in December 2013; and
- $8 million increase due to ancillary distribution revenues, primarily associated with OEB-approved regulatory accounts.

## Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of purchased electricity delivered to customers within our distribution service territory. These costs comprise the wholesale commodity cost of energy, the IESO wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy is based on the OEB's RPP or the market price for electricity. A discussion of the electricity rates can be found in the section "Regulation – Regulatory Proceedings – Electricity Rates."

Our purchased power costs increased by $399 million, or 13%, in 2014, compared to 2013. The components of the increase include the following:

- $291 million increase resulting from higher purchased power costs for customers who are not eligible for the RPP;
- $78 million increase resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers;

- $26 million increase resulting from the OEB transmission rate decision effective January 1, 2014;
- $10 million increase due to wholesale market service charges levied by the IESO;
- $4 million increase resulting from the IESO's Smart Metering Entity charge effective May 1, 2013; and
- $10 million decrease due to lower energy consumption in 2014, mainly resulting from a milder summer and a warmer fall in 2014.

### Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, which is substantially established under collective bargaining agreements, and materials, equipment and purchased services, which are subject to public tenders. Key enablers of the successful implementation of our work programs are our human and material resourcing strategies. Our human resources strategy is focused on hiring through our apprenticeship program and our association with universities, colleges and our unions, as well as skills development and retention, including earlier identification and more rapid development of staff who demonstrate management potential. Our skilled labour pool primarily consists of line, forestry, construction and stations staff who live and work across the province.

Our operation, maintenance and administration expenditures include work program costs and costs to support the operation and maintenance of the transmission and distribution systems. Also included in these costs are payments in lieu of property taxes related to our transmission and distribution lines, stations and buildings. Our transmission operation, maintenance and administration costs are incurred to sustain our high-voltage transmission stations, lines and rights-of-way, and include preventive and corrective maintenance costs related to our power equipment, overhead transmission lines, transmission station sites, and brush control. Our distribution operation, maintenance and administration costs are required to maintain our low-voltage distribution system, and include costs related to distribution line clearing and brush control, line maintenance and repair, as well as land assessment and remediation (LAR). Our company continues to focus on managing its costs, while continuing to complete our planned work programs for both our Transmission and Distribution Businesses.

| *Year ended December 31 (millions of Canadian dollars)* | **2014** | 2013 | $ Change | % Change |
|---|---|---|---|---|
| Transmission | **394** | 375 | 19 | 5 |
| Distribution | **742** | 672 | 70 | 10 |
| Other | **56** | 59 | (3) | (5) |
| | **1,192** | 1,106 | 86 | 8 |

#### *Transmission*

Our 2014 transmission operation, maintenance and administration costs increased by $19 million, or 5%, compared to 2013.

Our 2014 transmission work program costs were $240 million, compared to $237 million in 2013, an increase of $3 million. The increase is mainly due to the following:

- increased forestry expenditures related to brush control and line clearing on our transmission rights-of-way;
- a higher volume of corrective and preventive maintenance on power equipment and overhead lines; and
- higher transmission site facilities maintenance requirements.

Our 2014 transmission support costs were $154 million, compared to $138 million in 2013, an increase of $16 million. The increase is mainly due to the following:

- a one-time reduction to our provision for payments in lieu of property taxes in 2013 related to transmission stations for the years 1999 to 2012, inclusive, following the finalization of the related regulations and receipt of a final assessment of our property tax returns;
- partially offset by lower expenditures due to the recovery of insurance proceeds for the 2013 floods at our Richview and Manby transmission stations; and
- increased attribution of overheads to capital project expenditures in 2014.

***Distribution***

Our 2014 distribution operation, maintenance and administration costs increased by $70 million, or 10%, compared to 2013.

Our 2014 distribution work program costs were $599 million, compared to $515 million in 2013, an increase of $84 million. The increase is mainly due to the following:

- our customer service recovery initiatives and the increase in our bad debt expense, resulting from higher electricity consumption due to a substantially colder than normal winter, combined with higher electricity prices and the suspension of certain collection tools and efforts during several months in 2014. We resumed some of our collection tools and efforts in September 2014.

Our 2014 distribution support costs were $143 million, compared to $157 million in 2013, a decrease of $14 million. The decrease is mainly due to the following:

- decreased expenditures in 2014 related to CIS, as it was placed in-service in May 2013.

**Depreciation and Amortization**

Our 2014 depreciation and amortization costs increased by $46 million, or 7%, compared to 2013. This increase was primarily attributable to higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program.

**Financing Charges**

Our 2014 financing charges increased by $19 million, or 5%, compared to 2013. The increase is primarily due to the following:

- an increase in interest expense on our long-term debt due to a higher average level of debt;
- partially offset by a lower average interest rate.

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

The provision for payments in lieu of corporate income taxes (PILs) decreased by $20 million, or 18%, to $89 million in 2014, compared to 2013. The decrease is primarily due to lower levels of pre-tax income in 2014 compared to 2013.

**Net Income**

Our 2014 net income attributable to the Shareholder of Hydro One decreased by $54 million, or 7%, to $749 million, compared to 2013. The decrease is primarily due to the following:

- $70 million increase in our 2014 distribution operation, maintenance and administration costs, mainly due to our customer service recovery initiatives and the increase in our bad debt expense, resulting from higher electricity consumption due to a substantially colder than normal winter, combined with higher electricity prices and the suspension of certain collection tools and efforts during several months in 2014;
- $46 million increase in our 2014 depreciation and amortization costs, mainly due to higher property, plant and equipment depreciation expense in 2014, related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program; and
- partially offset by a $59 million increase in our 2014 transmission revenues, mainly due to new OEB-approved 2014 transmission rates.

## QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2013 through to December 31, 2014. This information has been derived from our unaudited interim Consolidated Financial Statements and our audited annual Consolidated Financial Statements, which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

| *(millions of Canadian dollars)* | **2014** | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|
| *Quarter ended* | **Dec. 31** | **Sept. 30** | **Jun. 30** | **Mar. 31** | Dec. 31 | Sept. 30 | Jun. 30 | Mar. 31 |
| Total revenue | **1,662** | **1,556** | **1,566** | **1,764** | 1,557 | 1,542 | 1,403 | 1,572 |
| Net income attributable to Shareholder of Hydro One | **221** | **173** | **115** | **240** | 160 | 218 | 168 | 257 |
| Net income to common Shareholder of Hydro One | **216** | **169** | **110** | **236** | 155 | 214 | 163 | 253 |

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

### 2014 Fourth Quarter Results of Operations

| *Three months ended December 31 (millions of Canadian dollars)* | **2014** | 2013 | $ Change | % Change |
|---|---|---|---|---|
| Revenues | **1,662** | 1,557 | 105 | 7 |
| Purchased power | **893** | 794 | 99 | 12 |
| Operation, maintenance and administration | **247** | 286 | (39) | (14) |
| Depreciation and amortization | **190** | 184 | 6 | 3 |
| | **1,330** | 1,264 | 66 | 5 |
| **Income before financing charges and provision for payments in lieu of corporate income taxes** | **332** | 293 | 39 | 13 |
| Financing charges | **98** | 93 | 5 | 5 |
| **Income before provision for payments in lieu of corporate income taxes** | **234** | 200 | 34 | 17 |
| Provision for payments in lieu of corporate income taxes | **15** | 40 | (25) | (63) |
| **Net income** | **219** | 160 | 59 | 37 |
| Net income (loss) attributable to noncontrolling interest | **(2)** | – | (2) | (100) |
| **Net income attributable to Shareholder of Hydro One** | **221** | 160 | 61 | 38 |

Our total revenues for the three months ended December 31, 2014 were $1,662 million, compared to $1,557 million during the same period in 2013, an increase of $105 million or 7%. The increase is mainly due to the following:

- the recovery of higher purchased power costs;
- new transmission and distribution rates effective January 1, 2014;
- the OEB's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions and the disposition of certain OEB-approved transmission regulatory accounts;

- partially offset by lower average Ontario 60-minute peak demand and energy consumption in the fourth quarter of 2014, mainly due to milder weather in the fall of 2014; and
- lower ancillary revenues, primarily associated with OEB-approved regulatory accounts.

Our purchased power costs for the three months ended December 31, 2014 were $893 million, compared to $794 million during the same period in 2013, an increase of $99 million or 12%. The increase is mainly due to the following:

- higher purchased power costs for customers who are not eligible for the RPP;
- partially offset by lower energy consumption in the fourth quarter of 2014, mainly due to milder weather in the fall of 2014;
- wholesale market service charges levied by the IESO; and
- OEB transmission rate decision effective January 1, 2014.

Our operation, maintenance and administration costs for the three months ended December 31, 2014 were $247 million, compared to $286 million during the same period in 2013, a decrease of $39 million or 14%. The decrease is mainly due to the following:

- decreased distribution operation, maintenance and administration costs, primarily due to lower storm response expenditures as a result of lower storm activity in 2014, compared to 2013; and
- decreased expenditures related to brush control and distribution line maintenance work.

Our depreciation and amortization costs for the three months ended December 31, 2014 were $190 million, compared to $184 million during the same period in 2013, an increase of $6 million or 3%. The increase is mainly due to higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program.

Our financing charges for the three months ended December 31, 2014 were $98 million, compared to $93 million during the same period in 2013, an increase of $5 million or 5%. The increase is mainly due to the following:

- an increase in interest expense on our long-term debt due to a higher average level of debt; and
- partially offset by a lower average interest rate.

Our provision for PILs for the three months ended December 31, 2014 was $15 million, compared to $40 million during the same period in 2013, a decrease of $25 million or 63%. The decrease is due to the following:

- changes in net temporary differences, such as capital cost allowance in excess of depreciation, deductions for pension payments made in excess of amounts expensed for accounting purposes, and interest deducted for tax purposes in excess of interest expensed for accounting purposes; and
- partially offset by higher pre-tax income for the three months ended December 31, 2014 compared to the same period in 2013.

Net income attributable to the Shareholder of Hydro One for the three months ended December 31, 2014 was $221 million, compared to $160 million during the same period in 2013, an increase of $61 million or 38%. The increase is mainly due to the following:

- decreased distribution operation, maintenance and administration costs, primarily due to lower storm response expenditures as a result of lower storm activity in 2014, compared to 2013, and decreased expenditures related to brush control and distribution line maintenance work;
- a decrease in our provision for PILs, primarily due to changes in net temporary differences; and
- an increase in our 2014 transmission revenues, mainly due to new OEB-approved 2014 transmission rates.

## LIQUIDITY AND CAPITAL RESOURCES

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

### Summary of Sources and Uses of Cash

| *Year ended December 31 (millions of Canadian dollars)* | **2014** | 2013 |
|---|---|---|
| **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 | **72** | – |
| Dividends paid | **(287)** | (218) |
| **Investing activities** | | |
| Capital expenditures | **(1,504)** | (1,387) |
| Acquisition of Norfolk Power | **(66)** | – |
| Proceeds from investment | **250** | – |
| **Other financing and investing activities** | **(38)** | (14) |
| **Net change in cash and cash equivalents** | **(465)** | 370 |

### Operating Activities

Net cash from operating activities decreased by $148 million to $1,256 million in 2014, compared to 2013. The decrease was primarily due to the following:

- lower 2014 net income, compared to 2013;
- changes in accrual balances, mainly related to timing of capital projects;
- changes in regulatory accounts, including the retail settlement and external revenue variance accounts; and
- partially offset by higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program.

### Financing Activities

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

Our Commercial Paper Program is supported by our $1,500 million committed revolving credit facility with a syndicate of banks, which matures in June 2019. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

At December 31, 2014, we had $8,923 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2015 and 2064. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. At December 31, 2014, $1,187 million remained available until October 2015.

We rely on debt financing through our MTN Program and our Commercial Paper Program to repay our existing indebtedness and fund a portion of our capital expenditures. The credit ratings assigned to our debt securities by external rating agencies are important to our ability to raise capital and funding to support our business operations. Maintaining strong credit ratings allows us to access capital markets on competitive terms. A material downgrade of our credit ratings would likely increase our cost of funding significantly, and our ability to access funding and capital through the capital markets could be reduced. Our corporate credit ratings from approved rating organizations are as follows:

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

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets, and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that third party debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We were in compliance with all of these covenants and limitations as at December 31, 2014.

In 2014, we issued $628 million of long-term debt under our MTN Program, compared to $1,185 million of long-term debt issued in 2013. In 2014, we also repaid $750 million in maturing long-term debt, compared to $600 million of long-term debt repaid in 2013. In addition, long-term debt totalling $26 million assumed on the Norfolk Power acquisition was repaid in September 2014. We had no short-term notes outstanding at December 31, 2014 or December 31, 2013.

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

During 2014, we paid dividends to the Province in the amount of $287 million, consisting of $269 million in common share dividends and $18 million in preferred share dividends, compared to dividends of $218 million, consisting of $200 million of common share dividends and $18 million of preferred share dividends, paid to the Province in 2013.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns to our Shareholder.

### Investing Activities

During 2014, we continued to focus on making important investments in our transmission and distribution systems to address our aging power system infrastructure, improve our systems' reliability and performance, and improve service to our customers. We made capital investments totalling $1,530 million in 2014, compared to $1,394 million of capital investments in 2013, and have placed $1,574 million of new assets in-service in 2014, compared to $1,491 million of new assets placed in-service in 2013.

Capital investments consist of cash capital expenditures and related accruals. Capital investments primarily relate to sustaining, enhancing and reinforcing our transmission and distribution infrastructure.

| *Year ended December 31 (millions of Canadian dollars)* | **2014** | 2013 | $ Change | % Change |
|---|---|---|---|---|
| Transmission | **845** | 714 | 131 | 18 |
| Distribution | **680** | 673 | 7 | 1 |
| Other | **5** | 7 | (2) | (29) |
| **Total capital investments** | **1,530** | 1,394 | 136 | 10 |

***Transmission Capital Investments***

Our 2014 transmission capital investments were $845 million, compared to $714 million in 2013, an increase of $131 million or 18%, primarily due to sustainment programs to address our aging infrastructure. Given the aging of our infrastructure, we have ongoing investment plans which are designed to reliably power our economy and to support the innovation that can be expected over the next decade.

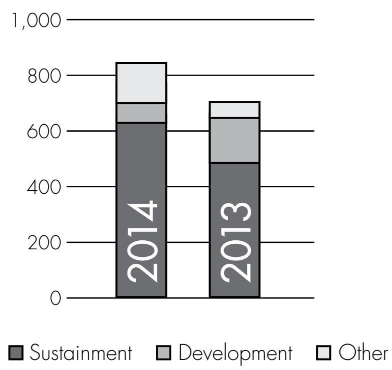
The following table presents the main components of our transmission capital investments during 2014 and 2013.

| *Year ended December 31 (millions of Canadian dollars)* | **2014** | 2013 | $ Change | % Change |
|---|---|---|---|---|
| Sustainment | **625** | 481 | 144 | 30 |
| Development | **132** | 170 | (38) | (22) |
| Other | **88** | 63 | 25 | 40 |
| **Total transmission capital investments** | **845** | 714 | 131 | 18 |

*Sustainment Transmission Capital Investments*

Our current transmission sustainment programs include protection and control systems, wood poles, breakers and high-voltage instrument transformer replacements. Our 2014 transmission sustainment capital investments were $625 million, compared to $481 million in 2013, an increase of $144 million or 30%. The increase was mainly due to the following:

**Transmission Capital Investments**
*(millions of dollars)*




- several system re-investments, including the Gerrard and Timmins transmission stations and new type of breakers at our Bruce Transmission Station, which progressed in 2014, as well as completed projects, such as the Pinard Transmission Station Breakers and the Wallaceburg Transmission Station;
- several replacements of end-of-life power transformers at our Pembroke Transmission Station in eastern Ontario, and our Hanover, Allanburg, and Elmira transmission stations in southwestern Ontario, as well as the emergency replacement of a unit at the Trafalgar Transmission Station;
- increased work within our station and lines equipment replacement and refurbishment projects and programs, including our investment to address the condition of the conductors on the 170 kilometre 230 kV circuit from the Chats Falls Switching Station to the Havelock Transmission Station in southeastern Ontario, and increased work on overhead lines wood pole structure replacements; and
- increased volume of replacements related to addressing aging protection and control equipment.

*Development Transmission Capital Investments*

Our current transmission development projects include transmission system upgrades, local area supply projects, and inter-area network projects. These investments will expand and reinforce power reliability for electricity customers throughout the province, including our residential and industrial customers. Our 2014 development capital investments to expand and reinforce our transmission system were $132 million, compared to $170 million in 2013, a decrease of $38 million or 22%. The decrease was mainly due to the following:

- the successful completion of our Sundusk and Summerhaven Switching Stations upgrades in 2013 to incorporate renewable energy into our transmission system; and
- reduced expenditures related to some of our major projects which were completed in 2014, such as the Lambton to Longwood Transmission Upgrade Project, the Barwick Transmission Station, and the Allanburg Transmission Station to ensure mandatory transmission system standards are met.

*Other Transmission Capital Investments*

Our 2014 other transmission capital investments were $88 million, compared to $63 million in 2013, an increase of $25 million or 40%. The increase was mainly due to the following:

- the development phase investment in our Network Management System Project, a critical operating tool used for monitoring and control of our transmission system;
- the investment in our Payroll Transformation Project to realize various process efficiencies; and
- partially offset by a decrease from the higher investments in 2013 as a result of emergency flood restoration work at our Richview Transmission Station resulting from a major rainstorm in July 2013.

***Major Transmission Projects***

Our company successfully advanced or completed a number of transmission capital investments projects during 2014. The following table summarizes the status of our major projects at December 31, 2014:

| Project Name | Location | Type | Planned In-Service Date | Approved Budget | Capital Cost To-Date | Current Status |
|---|---|---|---|---|---|---|
| Lambton to Longwood Transmission Upgrade | Sarnia area to west of London area Southwestern Ontario | Transmission line upgrade | 2014 | $41 million | $24 million | Placed in-service in September 2014 |
| Barwick Transmission Station | Rainy River/Fort Frances Northwestern Ontario | New transmission station | 2014 | $25 million | $21 million | Placed in-service in September 2014 |
| Allanburg Transmission Station | Niagara area Southwestern Ontario | Transmission station upgrade | 2014 | $33 million | $29 million | Placed in-service in December 2014 |
| Toronto Midtown Transmission Reinforcement | Toronto Southwestern Ontario | New transmission line | 2015 | $115 million | $83 million | Project is in progress |
| Guelph Area Transmission Refurbishment | Guelph area Southwestern Ontario | Transmission line upgrade | 2016 | $103 million | $24 million | Project is in progress |
| Manby Transmission Station | Toronto Southwestern Ontario | Transmission station upgrade | 2016 | $24 million | $14 million | Project is in progress |
| Clarington Transmission Station | Oshawa area Eastern GTA | New transmission station | 2017 | $297 million | $42 million | Project is in progress |
| Supply to Essex County Transmission Reinforcement | Windsor-Essex area Southwestern Ontario | New transmission line and station | 2018 | To be determined | – | Section 92 application filed with OEB in January 2014 |
| Northwest Bulk Transmission Line | Thunder Bay Northwestern Ontario | New transmission line | As early as 2020 | To be determined | – | OPA recommendation letter received in October 2014 |

*Lambton to Longwood Transmission Upgrade*

Our Lambton to Longwood Transmission Upgrade project involved the upgrade of approximately 70 kilometres of 230 kV double-circuit transmission line between our Lambton and Longwood transmission stations in southwestern Ontario. The investment refurbished 36 tower foundations, replaced the conductor with a higher capacity wire and replaced insulators along the line. This project involved an innovative new technology that allowed the vast majority of the towers to remain in place, and will enable approximately 500 MW of additional clean energy to be connected to the grid. The additional capacity on the grid will also contribute to meeting provincial energy supply targets for installed non-hydroelectric renewable generation by 2021.

*Barwick Transmission Station*

Our Barwick Transmission Station provides more capacity for communities between Rainy River and Fort Frances in northwestern Ontario, thereby strengthening the reliability of the power supply for both residential and commercial customers in the area. The Barwick Transmission Station consists of two 115 kV/44 kV transformers and allows for shorter spans of 44 kV power lines to connect customers to our system, ultimately improving the reliability of their power supply. The project involved in-house construction crews, local vendors and labour from the Rainy River First Nation community.

*Allanburg Transmission Station*

As a result of new generation connections and various transmission project upgrades in the Niagara area of southwestern Ontario, the Allanburg Transmission Station 115 kV switchyard short circuit level has increased and exceeded breaker capability limits. Consequently, upgrade work was required to replace 15 end-of-life breakers with upgraded short circuit capability in accordance with the TSC standards.

*Toronto Midtown Transmission Reinforcement*

Supply to the midtown Toronto area is currently provided by three 115 kV circuits between the Leaside Transmission Station and the Wiltshire Transmission Station. These circuits also supply the Bridgman and Dufferin Transmission Stations and provide load transfer capability between the Leaside and Manby transmission stations. The Toronto Midtown Transmission Reinforcement project includes the replacement of an aging underground cable which is nearing its end of life; the installation of an additional 115 kV circuit between the Leaside and Bridgman transmission stations to relieve loading on the existing circuits which are currently operating above their capacity; and the installation of new equipment at the Leaside Transmission Station, and Bayview, Birch and Bridgman Junctions. These transmission infrastructure reinforcements are intended to reduce the risk of power outages, improve reliability for electricity customers, and provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west.

*Guelph Area Transmission Refurbishment*

The Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in Guelph and the surrounding area, includes the installation of two new autotransformers at the existing Cedar Transmission Station, an upgrade of approximately five kilometres of an existing transmission line from 115 kV to 230 kV in south-central Guelph, and an upgrade of the existing Guelph North Junction to a switching station by installing new facilities and fencing. These refurbishments will reinforce the electricity supply and will minimize the impact of any major transmission outages on area customers.

*Manby Transmission Station*

The Manby Transmission Station project will upgrade the station short circuit capability and install higher rated breakers, which will permit incorporation of new renewable generation in the central Toronto area. Upgrade work requires the replacement of 16 end-of-life breakers and other components in the 115 kV Manby switchyard.

*Clarington Transmission Station*

To accommodate the eventual closure of the Pickering Nuclear Generating Station, the Clarington Transmission Station will provide additional autotransformer capacity to reliably supply load in the eastern GTA. Upon completion, the Clarington Transmission Station will consist of two 500/230 kV autotransformers and a 230 kV switchyard, and will connect to the existing 230 kV and 500 kV transmission lines. The project will enable future electricity demand growth in the local area and provide the area with the necessary facilities to ensure a safe, reliable supply of electricity to existing and future customers.

*Supply to Essex County Transmission Reinforcement Project*
On January 22, 2014, Hydro One Networks submitted a Leave to Construct application to the OEB under Section 92 of the *OEB Act* to construct a new 13-kilometre 230 kV double-circuit transmission line in the Windsor-Essex region. The new transmission line will connect to a proposed transmission station in the Municipality of Leamington and an existing 230 kV transmission line between Chatham and Windsor. The new transmission line and transmission station will address future growth in electricity demand and anticipated expansion in the local agricultural sector and improve the reliability of electricity supply in the broader Windsor-Essex region.

*Northwest Bulk Transmission Line*
In November 2013, the Minister of Energy issued a Directive to the OEB, which in turn issued a Decision and Order on January 9, 2014, to amend the transmission licence of Hydro One Networks to develop and seek approval for the Northwest Bulk Transmission Line Project, an expansion and reinforcement of the transmission system in the area west of Thunder Bay in northwestern Ontario. The project consists of a new transmission line that would increase transmission capacity and maintain the reliability of electricity supply to meet forecasted electricity demand growth and accommodate new generation capacity. Over the long term, it would also enhance the potential for development and connection of renewable energy facilities. Because of its importance to the region, this new line has been identified as a priority project in Ontario's LTEP. The Northwest Bulk Transmission Line Project will be developed by our company in cooperation with Infrastructure Ontario. The scope and timing of the project shall be in accordance with the recommendations of the OPA.

On October 1, 2014, Hydro One received a letter from the OPA outlining the scope and timing of the Northwest Bulk Transmission Line Project. The scope of the development work will include preliminary design and engineering, cost estimation, public engagement and consultation, routing and siting, and the preparation of an environmental assessment in support of this project. Hydro One is currently initiating the development work for the project and discussions are ongoing with Infrastructure Ontario on the project plan and related accountabilities.

### *Other Transmission Capital Investments*

*Pan American (Pan Am) Games*
The Pan Am Games project tracking initiative is underway to ensure that we provide a high level of electricity supply reliability to the Pan Am and Parapan Am Games during the summer of 2015, and that operating, maintenance and capital work plans are coordinated across lines of business to minimize outage risks to the venues hosting the 2015 Pan Am and Parapan Am Games. Key major capital projects and site-specific maintenance work in the GTA are being monitored on a monthly basis to ensure our customer commitments are met. This work will ultimately benefit all of our customers in the GTA.

*Niagara Reinforcement Project*
This project comprises the construction of 76 kilometres of 230 kV line from our Allanburg Transmission Station in the Niagara area to our Middleport Transmission Station in the Hamilton area. The Niagara Reinforcement Project status is considered substantially on time, with the exception that some project work has been delayed due to access issues related to Aboriginal land claims on a section of the line.

### *Distribution Capital Investments*

Our 2014 distribution capital investments were $680 million, compared to $673 million in 2013, an increase of $7 million or 1%, primarily due to our distribution sustainment programs to address our aging infrastructure.

The following table presents the main components of our distribution capital investments during 2014 and 2013.

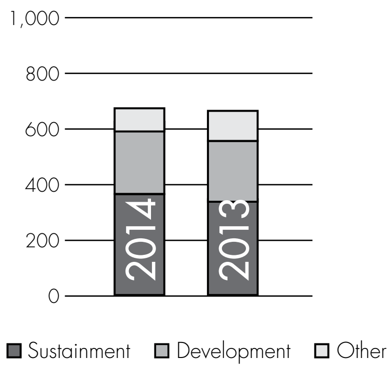
| *Year ended December 31 (millions of Canadian dollars)* | **2014** | 2013 | $ Change | % Change |
|---|---|---|---|---|
| Sustainment | **356** | 324 | 32 | 10 |
| Development | **236** | 235 | 1 | – |
| Other | **88** | 114 | (26) | (23) |
| **Total distribution capital investments** | **680** | 673 | 7 | 1 |

*Sustainment Distribution Capital Investments*

Our current distribution sustainment programs include wood pole and meter replacements, emergency work for storm restoration, distribution station refurbishments and upgrades, and work related to joint-use and relocation of our distribution lines. Our 2014 distribution sustainment capital investments were $356 million, compared to $324 million in 2013, an increase of $32 million or 10%. The increase is mainly due to the following:

- increased investments in meter replacements, including Itron Sentinel 16S meter replacements and Field Metering Services installations;
- higher volume of end-of-life wood pole replacements;
- increased focus on capital lines work, mainly due to the lines large sustainment initiatives program;
- increased work within our station refurbishment programs due to more refurbishments accomplished in 2014; and
- partially offset by less storm restoration work in 2014 due to lower storm activity compared to 2013.

**Distribution Capital Investments**
*(millions of dollars)*




*Development Distribution Capital Investments*

Our current development projects to expand and reinforce our distribution network include new customer connections and upgrades, system capability reinforcement projects, line transfers requested by our customers, and connections to new generation facilities. Our 2014 distribution development capital expenditures were $236 million, compared to $235 million in 2013, an increase of $1 million. The increase is mainly due to the following:

- increased work for subdivision connections, new customer connections, and upgrades;
- the purchase of retail revenue meters for all new connections and service upgrades; and
- partially offset by less lines and stations work related to upgrading and adding capacity to our distribution system.

*Other Distribution Capital Investments*

Our 2014 other distribution capital expenditures were $88 million, compared to $114 million in 2013, a decrease of $26 million or 23%. The decrease is mainly due to the following:

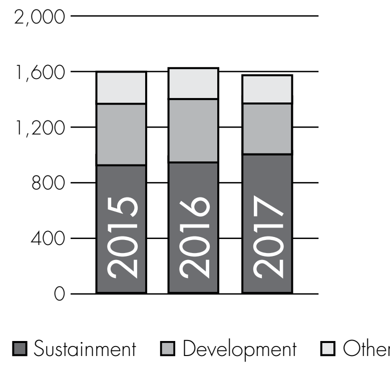
- decreased expenditures in 2014 related to CIS, as it was placed in-service in May 2013;
- decrease due to higher investments in 2013 as a result of emergency flood restoration work at our Richview Transmission Station resulting from a major rainstorm in July 2013; and
- partially offset by the investment in our Payroll Transformation Project to realize various process efficiencies.

## Future Capital Investments

Our capital investments for 2015 are budgeted at approximately $1,600 million. Our 2015 capital budgets for our Transmission and Distribution Businesses are approximately $900 million and $700 million, respectively. Consolidated capital investments are expected to be approximately $1,625 million in 2016 and $1,575 million in 2017. These investment levels reflect our continued sustainment focus on our aging infrastructure. Our sustainment program capital investments are expected to be approximately $925 million in 2015, $950 million in 2016 and $1,000 million in 2017. Our development capital investments are expected to be approximately $450 million in 2015,

$450 million in 2016, and $375 million in 2017. Our development projects include the inter-area network upgrades that reflect supply mix policies, local area supply improvements, the ADS Project, new load and generation connections and requirements to enable DG, and customer demand work. Other capital investments are expected to be $225 million in 2015, $225 million in 2016, and $200 million in 2017. This includes investments in operating infrastructure integration, information technology (IT), fleet services and facilities, and real estate. Our future capital investments amounts do not include future LDC acquisitions.

**Future Capital Investments**
*(millions of dollars)*




Hydro One's plans to maintain, refurbish or replace existing facilities are developed on the basis of maintenance standards, asset condition assessments and end-of-life criteria specific to each type of equipment. Priorities are assigned to each type of investment based on the risks that it mitigates. In addition, investments that are cross-functional and/or require IT involvement are governed by a productivity framework with substantive benefits. These capital investment plans are also included in our rate filings submitted to the OEB for approval.

***Transmission***

Transmission capital investments are incurred to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. Our sustainment program future capital investments include the replacement and/or refurbishment of end-of-life air blast circuit breakers and switchgear, high-voltage underground cables, high-voltage circuits and power transformers. Also, given the current age of our assets and infrastructure and to achieve significant cost efficiencies, we have moved to a more integrated station and circuit centric refurbishments approach than has been undertaken historically in order to address and bundle component and refurbishment replacements that would have occurred over time into one project. These investments are necessary to ensure that we maintain our current levels of supply to our customers and continue to meet all regulatory, compliance, safety and environmental objectives.

Our future development capital investments include the Clarington Transmission Station Project to install additional autotransformer capacity in the eastern GTA; the Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in south-central Guelph; investments in ADS; requirements to enable DG; the Supply to Essex County Transmission Reinforcement Project, a new transmission line in the Windsor-Essex region; and the Toronto Midtown Transmission Reinforcement Project, a new circuit in midtown Toronto and the refurbishment of an underground cable. Development capital investments also include the connection of new generation projects to the transmission system; however, these investments are largely funded by the connecting generation customers.

Based on the OEB's framework for competitive designation for the development of eligible transmission projects, we did not include in our budgeted future capital investments any projects that could meet the definition of expansions. We do not plan to undertake large capital investments without a reasonable expectation of recovering them through our rates.

The actual timing and investments of many development projects are uncertain as they are dependent upon various regulatory approvals, negotiations with customers, neighbouring utilities and other stakeholders, and consultations with First Nations and Métis communities. Projects are also dependent upon the timing and level of generator contributions for enabling facilities.

***Distribution***

Distribution capital investments include the sustainment of our infrastructure. Our core work will continue to focus on maintaining the performance of our aging distribution asset base through renewal and refurbishment activities. Planned capital investments include the continued replacements of equipment and components that are beyond their expected service life, as well as increased wood pole replacements and distribution station refurbishments. Sustainment capital investments related to the smart metering project will decrease through 2016.

Distribution development capital investments are expected to be relatively stable through 2016, with the exception of capital contributions for capacity improvements at the Orleans Transmission Station in the Ottawa area in 2015 and the Hanmer Transmission Station in the Sudbury area in 2016. We will continue to make investments required to connect new load and DG customers, as well as investments to ensure the system is capable of supplying customer needs. During 2015 and 2016, a number of our projects will address local load growth issues. Generation connection investments, consisting of OPA-contracted FIT and MicroFIT Program generators, will decrease as the volume of connections is expected to decrease.

The ADS Project continues to pilot various technologies and related capital investments and will begin to decrease in 2015 and 2016. Pilot technologies include improvements to outage response management through more effective resource dispatch, automation to isolate faults where needed, and the dynamic regulation of voltage to reduce power losses.

### 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 our 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 our debt and other major contractual obligations, as well as other major commercial commitments:

| *December 31, 2014 (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[1] | 8,923 | 550 | 1,100 | 978 | 6,295 |
| Long-term debt – interest payments[1] | 7,765 | 419 | 774 | 677 | 5,895 |
| Pension[2] | 361 | 174 | 187 | – | – |
| Environmental and asset retirement obligations[3] | 284 | 19 | 73 | 68 | 124 |
| Outsourcing agreements[4] | 701 | 179 | 291 | 218 | 13 |
| Operating lease commitments | 45 | 7 | 19 | 10 | 9 |
| **Total contractual obligations** | 18,079 | 1,348 | 2,444 | 1,951 | 12,336 |
| | | | | | |
| **Other commercial commitments** *(by year of expiry)* | | | | | |
| Bank line[5] | 1,500 | – | – | 1,500 | – |
| Letters of credit[6] | 134 | 134 | – | – | – |
| Guarantees[6] | 331 | 331 | – | – | – |
| **Total other commercial commitments** | 1,965 | 465 | – | 1,500 | – |

[1] The "long-term debt – principal repayments" amounts are not charged to our results of operations, but are reflected on our Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with the long-term debt is recorded in financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

[2] Contributions to the Hydro One Pension Fund were generally made one month in arrears. However, due to the interest rate environment, the annual contributions have been prepaid in each of the last two years. No contribution prepayments are anticipated in 2015. The 2015 and 2016 minimum pension contributions are based on an actuarial valuation as at December 31, 2013. Pension contributions totalling $174 million were made during the year ended December 31, 2014. Minimum pension contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016, and will depend on future investment returns, changes in benefits, or actuarial assumptions. Pension contributions beyond 2016 are not estimable at this time.

[3] We record 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. We also record a liability for asset retirement obligations associated with the removal and disposal of asbestos-containing materials installed in some of our facilities, as well as the future decommissioning and removal of two of our switching stations. The forecasted expenditure pattern reflects our planned work programs for the periods.

[4] In 2014, we have finalized a new outsourcing agreement with Inergi for the provision of certain services, as well as a facilities outsourcing agreement with Brookfield. Details of the new outsourcing agreements can be found in the section "New Developments in 2014 – Other – Outsourcing Agreements." Based on the September 2013 Shareholder Resolution, the Province requires us to contract only with parties who are employed and physically located in Ontario when providing services to our company. The contractual amounts disclosed include an estimated contractual annual inflation adjustment in the range of 1.9% to 2.1%. Payments in respect of our outsourcing agreements are recorded in operation, maintenance and administration costs on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

[5] In support of our liquidity requirements, we have a $1,500 million revolving standby credit facility with a syndicate of banks maturing in June 2019.

[6] We currently have outstanding bank letters of credit of $126 million relating to retirement compensation arrangements. We provide 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, 2014, we have provided a letter of credit to the IESO in the amount of $8 million to meet our current prudential requirement. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of $330 million, and on behalf of two distributors using total guarantees of $1 million.

## RELATED PARTY TRANSACTIONS

We are owned by the Province. The Ontario Electricity Financial Corporation (OEFC), IESO, OPA, OPG, and the OEB are related parties to our company because they are controlled or significantly influenced by the Province. The following is a summary of our related party transactions during the year ended December 31, 2014:

### The Province

- During 2014, we paid dividends to the Province totalling $287 million, compared to $218 million paid in 2013.
- In November 2014, we 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. Ê

### IESO

- During 2014, we purchased power in the amount of $2,601 million from the IESO-administered electricity market, compared to $2,477 million purchased in 2013.
- We receive revenues for transmission services from the IESO, based on OEB-approved UTRs. Our 2014 transmission revenues include $1,556 million related to these services, compared to $1,509 million in 2013.
- We receive amounts for rural rate protection from the IESO. Our 2014 distribution revenues include $127 million related to this program, compared to $127 million in 2013.
- We receive revenues related to the supply of electricity to remote northern communities from the IESO. Our 2014 distribution revenues include $32 million related to these services, compared to $33 million in 2013.

### OPA

- The OPA funds substantially all of our CDM programs. The funding includes program costs, incentives, and management fees. During 2014, we received $33 million from the OPA related to these programs, compared to $34 million received in 2013.

### OPG

- During 2014, we purchased power in the amount of $23 million from OPG, compared to $15 million in 2013.
- Our company has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. Our 2014 other revenues include $12 million related to these service level agreements, compared to $9 million in 2013. Our 2014 operation, maintenance and administration costs related to the purchase of services with respect to these service level contracts were $1 million, compared to $1 million in 2013.

### OEFC

- During 2014, we made payments in lieu of corporate income taxes to the OEFC totalling $86 million, compared to payments of $138 million made in 2013.
- During 2014, we purchased power in the amount of $9 million from power contracts administered by the OEFC, compared to $8 million purchased in 2013.
- During 2014, our company paid a $5 million annual fee to the OEFC, compared to $5 million paid in 2013, 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.

### 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 2014, we incurred $12 million in OEB fees, compared to $12 million incurred in 2013.

At December 31, 2014, the amounts due from and due to related parties as a result of the transactions described above were $224 million and $227 million, respectively, compared to $197 million and $230 million at December 31, 2013, respectively. At December 31, 2014, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $214 million, compared to $217 million at December 31, 2013.

## CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

### Effect of Load on Revenue

Our load, based on normal weather patterns, is expected to increase in 2015 due to economic growth in all sectors of the Ontario economy, partially offset by the load impact of CDM and embedded generation. Overall load growth due to the economy alone is forecasted to be approximately 1.9%, with the commercial and industrial sectors slightly outperforming the residential sector. The load impacts of CDM and embedded generation are expected to have a negative impact on load growth of approximately 0.6% and 0.4%, respectively. On the whole, our load is expected to increase by approximately 0.9% in 2015. Our approved revenue requirement for 2015 has taken the negative load impact of CDM and embedded generation into account. A load growth below our load forecast, included in our approved revenue requirement, would negatively impact our financial results.

### Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements upon which our rates are based. The first component impacted by interest rates is our return on equity (ROE). The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. All other things being equal, we estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our ROE would reduce Hydro One Networks' transmission and distribution businesses' 2015 results of operations by approximately $20 million and $13 million, respectively. As interest rates decline, there is more risk of a decline in our net income. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

### Input Costs

In support of our ongoing work programs, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, general outline agreements, and vendor alliances and we also manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts on our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counterparties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

During 2014, we finalized a new outsourcing agreement with Inergi for the provision of certain services, as well as a facilities outsourcing agreement. Details of the new outsourcing agreements can be found in the section "New Developments in 2014 – Other – Outsourcing Agreements."

### Pension Plan

In 2014, we contributed approximately $174 million to our pension plan, compared to contributions of approximately $160 million made in 2013, and incurred $158 million in net periodic pension benefit costs, compared to $287 million incurred in 2013. We currently estimate our total annual pension contributions to be approximately $174 million for 2015 and $175 million for 2016, based on an actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Actuarial valuations are required to be filed at least every three years. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. In 2014, our pension plan experienced positive returns of approximately 12.3%, compared to approximately 17.9% in 2013.

Our 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."

## RISK MANAGEMENT AND RISK FACTORS

We have an Enterprise Risk Management (ERM) Program that aims at balancing business risks and returns. A company-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic goals. Our ERM program helps us to better understand uncertainty and its potential impact on our strategic goals. It sets out the uniform principles, processes and criteria for identifying, assessing, evaluating, treating, monitoring and communicating risks across all lines of business. It supports our Board of Directors' corporate governance needs and the due diligence responsibilities of senior management.

While our philosophy is that risk management is the responsibility of all employees, the Board of Directors annually reviews our company's risk tolerances, risk management policies, processes and accountabilities. Twice per year, the Board of Directors reviews our risk profile, which is the list of key risks prepared by senior management, and represents the greatest threats to meeting our strategic objectives. The Board of Directors' committees review risks relevant to their mandate at every meeting. The Audit, Finance and Pension Investment Committee of our Board of Directors annually reviews the status of our internal control framework.

Our President and Chief Executive Officer (CEO) has ultimate accountability for risk management. Our Leadership Team provides senior management oversight of our risk portfolio and our risk management processes. The leadership team provides direction on the evolution of these processes and identifies priority areas of focus for risk assessment and mitigation planning.

Our Chief Financial Officer (CFO) is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. The CFO has specific accountability for ensuring that ERM processes are established, properly documented and maintained by our company.

Our senior managers, line and functional managers are responsible for managing risks within the scope of their authority and accountability. Risk acceptance or mitigation decisions are made within the risk tolerances specified by the head of the subsidiary or function.

The CFO provides support to the committees of our Board of Directors, the President and CEO, the senior management team and key managers within our company. This support includes developing risk management frameworks, policies and processes, introducing and promoting new techniques, establishing risk tolerances, preparing annual corporate risk profiles, maintaining a registry of key business risks and facilitating risk assessments across our company. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems. Starting in 2013, our Board of Directors has taken on an enhanced role in our governance structure. Each committee of the Board of Directors will take accountability for reviewing specific risks of our company.

Key elements of our ERM Program enable us to identify, assess and monitor our risks effectively. These include having an ERM policy and framework which communicates our philosophy and process for risk management across our company. A discussion of risks is an integral part of each line of business' planning documents on an annual basis. Risk identification is also considered as part of each business case for investments. Finally, discrete risk assessments and workshops are performed for specific lines of business, key projects and various profiles, such as customer relationships and regulatory compliance. In order to drive consistency throughout our risk identification and risk management processes, we use a standard list of risk sources known as our risk universe. These sources are maintained in a single database that provides a consistent basis for risk identification and classification and serves as a repository for our risk assessments. All risk assessments in our company start with this risk universe. We also use standard risk criteria, which establish the metrics and terminology used for assessing and communicating on risks, and help ensure a consistent basis for our risk assessments and risk evaluations across all lines of business. Risk criteria include formally established risk tolerances and standard scales for assessing the probability of a risk materializing and the strength of controls in place to mitigate them.

Our key risks are as follows:

### Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors, appoint the Chair, and influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008, the Province made a declaration removing certain powers from our company's directors pertaining to the off-shoring of jobs under the 2001 Inergi Agreement. In 2011, the Province made a declaration preventing our company from seeking cost recovery through the regulatory process for the cost of upgrades required for either MicroFIT or Small FIT generators for costs related to investment and expenditures made. Effective September 30, 2013, the Province made a declaration regarding the outsourcing of services covered by the Inergi Agreement.

Effective December 17, 2014, the Province made a further declaration pursuant to the memorandum of agreement and section 108 of the *Business Corporations Act* (Ontario) regarding the provision of information, personnel and resources to the Premier's Advisory Council on Government Assets. By way of the declaration and concurrent Shareholder resolution, the Province restricted the rights, powers and duties of our Board of Directors, and at the same time assumed such rights, powers and duties, with respect to providing the Premier's Advisory Council on Government Assets, the Government or the Ministries and their advisors and consultants all information, assistance, personnel, resources and reports as and when requested and co-operating with those Government advisors tasked with providing recommendations on labour relations matters and pension-related matters. The directors are charged with carrying out the intention of the declaration and resolution, including taking such necessary steps to issue similar declarations and resolutions with respect to Hydro One Networks and Hydro One Brampton Networks. The Province could mandate the selling of all or part of our distribution business and this could have a material adverse effect on our company.

In 2009, the Province required our company, among other entities, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Our company's credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of our company's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, including any potential outcomes arising out of the recommendations of the Ontario Distribution Sector Review Panel's report, the Province's ownership of OPG, and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us, which could have a material adverse effect on our business.

### Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our Transmission and Distribution Businesses that permit a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, our net income for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

The OEB's new RRFE requires that the term of a custom rate application (distribution business) be a five-year period. There are risks associated with forecasting over a longer period. Changes in the industry may alter the investment needs or require changes to rate setting that could result in a significant impact on our company's capability to execute its plan.

Our load could also be negatively affected by successful CDM programs. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

We expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets, particularly given that new technology is required to support renewable generation, and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

In Ontario, the Market Rules mandate that we comply with the reliability standards established by NERC and NPCC. As a result, we will be required to comply with the United States Federal Energy Regulatory Commission's definition of Bulk Electric System unless we are granted an exception which will allow the application of the new definition in a cost-effective manner. Our company plans to submit exception applications and will look for recovery of costs incurred in meeting the definition in our rates; however, an adverse decision on an exception of recovery of costs could have an adverse effect on our company.

### Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

### First Nations and Métis Claims Risk

Some of our current and proposed transmission and distribution lines may traverse lands over which First Nations and Métis have Aboriginal, treaty or other legal claims. Although we have a recent history of successful negotiations, engagement and consultation with First Nations and Métis communities in Ontario, some communities and/or their citizens have expressed an increasing willingness to assert their claims through the courts, tribunals, or by direct action, which in turn can affect business activities. As a result, there exists uncertainty relating to business operations and project planning which could have an adverse effect on our company.

### Risk from Transfer of Assets Located on Reserves

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999, did not transfer title to some assets located on Reserves. Currently, OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy Reserves, our company must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the First Nation, OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. Where the agreement and permit are for transmission assets, our company must negotiate terms of payment. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. In 2014, we paid approximately $1 million to First Nations in respect of these agreements. OEFC will continue to hold these assets until we are able to negotiate agreements with First Nations and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel-generation facilities. In either case, the costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

### Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats, and by providing company-wide awareness training to our personnel. We also engage the services of external experts to evaluate the security of our IT infrastructure and controls. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Upon occurrence, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on our company.

### Workforce Demographic Risk

By the end of 2014, approximately 17% of our employees were eligible for retirement and by the end of 2015 up to 21% could be eligible. These percentages are not evenly spread across our workforce, but tend naturally to be most significant in the most senior levels of our staff and especially among management and executive staff. Accordingly our continued success will be tied to our ability to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of our work programs. This will be more challenging than in the past for a number of reasons.

Firstly, we expect the skilled labour market for our industry to be highly competitive in the future: many of our current employees and many of the employees we are going to be looking for possess skills and experience that will also be highly sought after by other organizations inside and outside the electricity sector; secondly, a variety of restraints on compensation and benefits for management and executive staff (including Bill 8) together with possible pension plan changes, and the uncertainty attaching to Hydro One's future size and scope as a result of the work of the Council, may adversely impact our ability to attract and retain the number and calibre of people we need in these roles.

In order to mitigate the potential effects of these factors, we are focused on earlier identification and more rapid development of staff who demonstrate the potential to progress quickly, especially those who demonstrate leadership potential, and on maintaining robust but flexible succession plans for the organization. In addition we continue to advance our apprenticeship and technical training programs to ensure that our future operational staffing needs will be met.

### Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals (Society). Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost-efficient manner. Although we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 similar to a previous reduction affecting management staff and increased pension contributions for PWU and Society staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2015, and the existing Society collective agreement will expire on March 31, 2016. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our company.

### Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt, including $550 million maturing in 2015 and $500 million maturing in 2016. We plan to incur capital expenditures of approximately $1,600 million in 2015 and $1,625 million in 2016. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies, and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures, and meet other obligations and requirements and, as a result, could have a material adverse effect on our company.

### Asset Condition

We continually monitor the condition of our assets to determine need and timing of preventative or remedial actions to maintain the desired level of service. Condition assessment is one of the key drivers for asset maintenance, refurbishment or replacement strategies to maintain equipment performance and provide reliable service quality. Our capital programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. However, if we are unable to carry out these plans in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

### Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. However, given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary LAR program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's PCB regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025, while our LAR expenditures are expected to be incurred over the period ending 2022. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities. Actual future expenditures may vary materially from the estimates used for the amount of the asset retirement obligation.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases.

We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our company.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our company.

### Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are 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. Our company contributed approximately $160 million in respect of 2013 and approximately $174 million in respect of 2014 to its pension plan to satisfy minimum funding requirements. Contributions beyond 2014 will depend on investment returns, changes in benefits and actuarial assumptions and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our company, and this risk may be exacerbated as the quantum of required pension contributions increase.

### Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into outsourcing arrangements with Inergi and Brookfield. Details of the new outsourcing agreements can be found in the section "New Developments in 2014 – Other – Outsourcing Agreements." If either of these outsourcing agreements are terminated for any reason or expire before a new supplier is selected, we could be required to incur significant expenses to transfer to another service provider or insource, which could have a material adverse effect on our business, operating results, financial condition or prospects.

### Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity price risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency-denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 40% common equity and 60% debt will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' 2015 net income by approximately $20 million and our Hydro One Networks' distribution business' 2015 net income by approximately $13 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counterparties. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlement Code. The failure to properly manage these risks could have a material adverse effect on our company.

### Risk Associated with Transmission Projects

Transmission projects involve either modifying existing or building new transmission lines and/or stations or both. Such projects are required primarily to address limitations on the transmission network to transfer power from generation sources to load centres, improve regional load supply capacity and reliability, connect new generators and load customers, and to meet new, or changes to, codes and standards.

In many cases, transmission investments are contingent upon one or more of the following approvals and/or processes: *Environmental Assessment Act* (Ontario) approval(s); receipt of OEB approvals which can include expropriation; and appropriate consultation processes with First Nations and Métis communities. Obtaining OEB and/or *Environmental Assessment Act* (Ontario) approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments which could adversely affect transmission reliability and/or our service quality, both of which could have a material adverse effect on our company.

With the introduction on August 26, 2010, of the OEB's competitive transmission project development planning process, in the absence of a government directive, all interested transmitters will be required to submit a bid to the OEB for possibly some identified enabler facilities and network enhancement projects. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, as bid costs are recoverable only by the successful proponent, additional costs for unsuccessful bids would be absorbed. This could have a material adverse effect on our company.

### Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks, which could have an adverse effect on our company.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated Financial Statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our 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 our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. We have identified the following critical accounting estimates used in the preparation of our Consolidated Financial Statements:

### Revenues

Our monthly distribution revenue is estimated based on wholesale electricity purchases. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The newly implemented CIS phase of our entity-wide system improvement project will allow us to use historical trends at a customer level to better estimate our unbilled revenue each period. This change in methodology for estimating revenue is anticipated to be implemented in 2015. Any changes in estimate will be accounted for prospectively.

### Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management'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 allowance for doubtful accounts on customer receivables is estimated 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.

### Regulatory Assets and Liabilities

Our 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. Our regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, and environmental liabilities. Our 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

We record 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.

In April 2014, Environment Canada enacted amendments to the existing PCB regulations, which included the extension of the end-of-use deadline from 2014 to 2025 for equipment containing certain concentrations of PCBs. Further discussion of the PCB amendments and related impact on our company can be found in the section "New Developments in 2014 – Other – Environment Canada Regulations."

### Employee Future Benefits

Our 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 our current and retired employees. Employee future benefits costs are included in our 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 our 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, 2014 decreased to 4.00% from 4.75% used at December 31, 2013, in conjunction with decreases in bond yields over this period. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities 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 our 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 2.00% per annum as at December 31, 2013 to approximately 1.70% per annum as at December 31, 2014. 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, 2014.

*Mortality Assumptions*
Our 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, 2014 was updated to 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). As at December 31, 2013, the draft tables published by the Canadian Institute of Actuaries were used.

*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 $23 million increase in 2014 interest cost plus service cost, and a $248 million increase in the year-end 2014 benefit liability.

## Asset Impairment
Within our regulated businesses, the carrying costs of most of our 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 our unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2014, no asset impairment had been recorded for assets within our regulated or unregulated businesses.

Goodwill represents the cost of acquired LDCs that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. We have concluded that goodwill was not impaired at December 31, 2014.

## 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, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2014, together with other financial information included in our securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Further, our 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 our company's DC&P and ICFR, our Certifying Officers concluded that our company's DC&P and ICFR were effective as at December 31, 2014.

## NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the Financial Accounting Standards Board (FASB) issued an accounting standards update that provides guidance on revenue recognition which 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 update is applicable to our company for the years and interim periods beginning on January 1, 2017. We are currently assessing the impact of adoption of this accounting standards update on our consolidated financial statements.

In August 2014, the FASB issued an accounting standards update that 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 update is applicable to our company for the year ending December 31, 2016, and for annual and interim periods thereafter. We do not anticipate that the adoption of this accounting standards update will have a significant impact on our consolidated financial statements.

In November 2014, the FASB issued an accounting standards update that provides guidance on accounting for hybrid financial instruments issued in the form of a share. This update is applicable to our company for the years and interim periods beginning on January 1, 2016. We are currently assessing the impact of adoption of this accounting standards update on our consolidated financial statements.

## OUTLOOK

We will achieve our mission and vision and remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our Shareholder. We will do this by continuing to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, championing people and culture, Shareholder value and productivity and cost-effectiveness. We continue to seek to strike the right balance between making prudent risk-based reliability investments and keeping customers' rates low. Effectively and efficiently managing costs is an important part of achieving this balance.

Given the nature of the work undertaken by our employees and contractors, safety remains our top priority. We will continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives, including maintaining our OHSAS 18001 standing.

We are focused on becoming a customer centric company and achieving our vision of improving customer satisfaction, maintaining affordable rates for the portion of the customers' bill within our control and building a trusted partner relationship with our customers. Our plan has taken into account discussions with our customers and reflects the planned development and delivery of targeted customer segment strategies, products and services which respond to our customers' unique needs. This includes realizing value from our new CIS, simplifying and shortening timeframes for the delivery of services, enhancing accessibility in person, by phone or through our web portal and/or our mobile application to ensure effective self-service for simple transactions, and delivering programs which help customers better manage their energy consumption. In addition, to further improve our customer service performance culture as a transparent, accountable and customer-focused organization, we have recently announced two new initiatives – a third party expert Customer Service Advisory Panel and our draft Customer Commitments.

We will continue to focus on driving our transformation to a culture that is accountability-based. All of our management staff received training under our Craft of Management program. In addition, a new Talent Management program was piloted in 2014 and will be rolled out company-wide in 2015. These programs will serve as the foundation for establishing that culture of accountability. Investments in these programs, coupled with existing programs which enhance employee skills and ability, will help us deliver best-in-class service to our customers, continue the drive to zero workplace injuries and create a great workplace that will lead to improved employee engagement. We remain focused on managing the resourcing requirements of an increasing work program through appropriate compensation policies, labour negotiations, use of outsourced multi-skilled staff and support of internal and external college and university training programs. Aging workforce demographics provide opportunities, through retirements, to restructure and transform the workforce.

Our assets are in the midst of a demographic change with an increasing proportion of assets reaching the end of their expected service life and an increasing average asset age. To ensure the electricity system's reliability in the public interest, we have planned for significant investments in transmission and distribution infrastructure. Our plan includes targeted, risk-based investments to maintain, refurbish and replace existing assets that are in poor condition and beyond their expected service life, within the policy set by the OEB. Investments in technology, such as the successful implementation of Asset Analytics, have provided us with real-time asset condition and performance data, giving us the ability to make asset optimization life-cycle decisions, and opportunities through planning and scheduling data to improve materials procurement and to deploy work crews to better manage work programs to meet customer needs.

The actual timing and expenditures in our business plan are predicated on obtaining various approvals including: OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities.

Over the last five years, we have replaced all of our core IT systems with a company-wide IT system. Further development of the existing IT platform will enable various tools to consistently provide a comprehensive and cascading information view of asset risks based on demographics, condition, performance, criticality, economics and utilization. In addition, we have introduced talent management, employee pay and time reporting enhancements to reduce costs, and to further develop and retain critical core competencies, skills and knowledge of our people. These new initiatives will allow us to effectively plan and reprioritize work and integrate customers' needs into multi-year investment plans. This outcome is consistent with the OEB's direction in its new Outcomes-Based Approach to regulation.

Our plan is focused on delivering integrated asset-to-work planning, optimized scheduling, and execution, as well as field mobility. Through our investment in our Workflow of the Future initiative (currently a pilot program), we will bring together data, analytics and mobility to allow our employees, especially those in the field, to do more at the job site with their mobile devices.

Significant opportunity resides with smart meters and the proliferation of ADS including energy efficiency, demand response and distributed-resource technologies over the long term. Our investments in this area will focus on reliability, customer needs and affordability. We will continue to invest on a prudent basis in the development of ADS and related grid modernization standards, customer demand work (connections and upgrades), smart meters, DG connections, including station upgrades, protection and control, new lines and some contestable work, for which we will receive customer capital contributions. There is little flexibility to reduce this work as most of it is customer demand driven.

Consistent with our corporate strategy, we will pursue an LDC consolidation approach that is robust but prudent, to facilitate the consolidation of Ontario's distribution sector. This is consistent with the Ontario Distribution Sector Review Panel's assessment that there are substantial efficiencies to be found through consolidation of Ontario LDCs and we are key to the solution. We will also work with our Shareholder to address the recommendations of the Council once they are finalized in the Council's final report which is anticipated in the spring of 2015. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects. The OEB notes in its *Framework for Transmission Project Development Plans* that where projects are otherwise equivalent or close in other factors, information such as socio-economic benefits, including First Nations involvement, could prove decisive in a competitive bid. As such, First Nations involvement in competitive bids is likely to become more prevalent.

## CHANGES TO OUR BOARD OF DIRECTORS

On March 7, 2014, our Shareholder, the Minister of Energy, on behalf of the Government of Ontario, announced that Sandra Pupatello would be appointed Chair of our Board of Directors, effective April 1, 2014, and on April 1, 2014, the Shareholder formally elected Ms. Pupatello as our new Chair. Ms. Pupatello is the Director of Business Development and Global Markets at PricewaterhouseCoopers Canada. She is also the Chief Executive Officer of the WindsorEssex Economic Development Corporation. Ms. Pupatello has been a member of our Board of Directors since November 2013.

On April 11, 2014, the following new members were added to our Board of Directors: William Limbrick, Tom Moss, and John Wiersma. William Limbrick was the Vice President of Information and Technology Services, Chief Information Officer of the IESO, and a Principal Consultant within the utilities practice of PricewaterhouseCoopers and Sun Life Assurance in the United Kingdom. Tom Moss is the former President and Chief Operating Officer of Telecom Ottawa, and has held strategic policy positions in the federal government at Treasury Board and Industry Canada. John Wiersma, P.Eng., is a former director of the ESA (Ontario) and IESO Board of Directors, and a former member of the Board of the Electrical and Utilities Safety Association and the Canadian Energy Efficiency Alliance.

On April 25, 2014, the following new members were added to our Board of Directors: Sally Daub, Maureen Sabia, and Carole Workman. Sally Daub is a director and former President and Chief Executive Officer of ViXS Systems, a former chair of the Small Business Agency of Ontario, and a former board member of the Information Technology Association of Canada and the Global Semiconductor Association. Maureen Sabia is the Chair of the Board of Canadian Tire Corporation Limited, and has an extensive background with organizations at the provincial and federal levels. She has been named one of Canada's Most Powerful Women and is also an officer of the Order of Canada. Carole Workman is a member of the Board of Allstate Insurance of Canada (Toronto). She also served on the Board of the Ottawa Hospital and its affiliates since 2007, and is a former member of the Board of Hydro Ottawa Holding Inc.

On April 1, 2014, James Arnett resigned from our Board of Directors. Mr. Arnett has been a member and Chair of our Board of Directors since March 2008. The Board of Directors terms for Michael Mueller, Walter Murray, Robert Pace, and Douglas Speers expired on April 11, 2014.

## FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy-related revenues and profit and their trend; statements regarding our transmission and distribution rates and customer bills resulting from our rate applications; statements related to the FIT program; statements about CDM; statements about our strategy, including our strategic objectives; statements regarding considerations of current economic conditions; statements regarding the new regional planning process; statements related to employee future benefits; expectations regarding First Nation involvement in competitive bids; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility; expectations regarding our financing activities; statements regarding our maturing debt; statements regarding our ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives (including productivity savings, process improvements, and customer satisfaction) and their completion dates; expectations regarding the recoverability of large capital investments; expectations regarding generation connection investments; statements regarding expected future capital and development investments, the timing of these expenditures and our investment plans; expectations regarding OPA recommendations; statements regarding contractual obligations and other commercial commitments; statements related to the OEB; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangements with Inergi and Brookfield and such future outsourcing arrangements; statements regarding customer service performance culture, including statements about the Customer Service Advisory Panel and Customer Commitments; expectations regarding work and costs of compliance with environmental and health and safety regulations; statements related to the 2013 LTEP; statements regarding recent accounting-related guidance; statements related to the Council; statements related to the Working Group on electricity sector pension plans; statements related to B2M LP; and statements related to LDC consolidation including our acquisition of Norfolk Power, Woodstock Hydro, and Haldimand Hydro. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our 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 us, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, the Province could mandate the selling of all or part of our distribution business, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction, including regulatory decisions regarding our revenue requirements, cost recovery, rates, acquisitions and divestitures;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risk that we 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, with maintaining a complex information technology system infrastructure, and with transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the ability to negotiate appropriate collective agreements;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital investments and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if either of our agreements with Inergi or Brookfield are terminated or expire before a new service provider is selected;
- the risks associated with changes in the forecasted long-term Government of Canada bond yield;
- the risks of counterparty default on our outstanding derivative contracts;
- the risks associated with current economic uncertainty and financial market volatility;
- the risk that our long-term credit rating would deteriorate;
- the inability to prepare financial statements using US GAAP, or IFRS, as applicable;

- the impact of the 2013 LTEP on our company and the costs and expenses arising therefrom;
- unanticipated changes in electricity demand or in our costs;
- the risk that unexpected capital investments may be needed to support renewable generation or resolve unforeseen technical issues; and
- the impact of the ownership by the Province of lands underlying our transmission system.

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

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

Additional information about the Company, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com and on the US Securities and Exchange Commission's website at www.sec.gov.

# 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**
President and Chief Executive Officer

**Ali R. Suleman**
Chief Financial Officer (Acting)

# 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

# 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)** | – Ê |
| **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)** | – Ê |
| **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.*

# 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.*

# 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

# 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 Ê |
| Net income | – | 803 | – | – | 803 Ê |
| Other comprehensive income | – | – | – | – | – Ê |
| Dividends on preferred shares | – | (18) | – | – | (18) Ê |
| Dividends on common shares | – | (200) | – | – | (200) Ê |
| **December 31, 2013** | 3,314 | 3,787 | (9) | – | 7,092 |

*See accompanying notes to Consolidated Financial Statements.*

# 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.*

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

**For the years ended December 31, 2014 and 2013**

## 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 Service Life | Rate Range | Rate 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*<br>*(millions of Canadian dollars)* | **2014**<br>**Carrying Value** | **2014**<br>**Fair Value** | 2013<br>Carrying Value | 2013<br>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 Ê

(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.

| *Year ended December 31* | Pension Benefits | | Post-Retirement and Post-Employment Benefits | |
|---|---|---|---|---|
| *(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 |

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*<br>*(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*<br>*(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.

# COMMUNITY

The Electricity Discovery Centre travelled more than 12,000 kilometres between September 2013 and September 2014 – the equivalent of driving from Halifax to Vancouver and back.

13 women were awarded the Women in Engineering Scholarship

**95%**
**of visitors**

would recommend visiting the Electricity Discovery Centre to family and friends

## YOUR COMMUNITY IS OUR COMMUNITY

From a partnership with a Northern Ontario college to the 12,000 kilometres travelled by our Electricity Discovery Centre, our 2014 investments are investments in Ontario's future.


Jim Burpee, President and CEO of the Canadian Electricity Association, presents Carmine Marcello, President and CEO of Hydro One, with the Sustainable Electricity Company designation.

### SUSTAINABLE ELECTRICITY COMPANY DESIGNATION

In December, the Canadian Electricity Association (CEA) awarded Hydro One with the Sustainable Electricity Company™ designation for our commitment to corporate responsibility and sustainable business practices. The designation recognizes the outstanding work Hydro One employees do in delivering electricity in a sustainable and socially responsible manner and in meeting the high expectations of our customers and the people of Ontario.

## WOMEN IN ENGINEERING SCHOLARSHIP

Hydro One has a long history of helping female students who are pursuing non-traditional careers. In October, we launched the Women in Engineering Scholarship for up to 15 women studying engineering at the undergraduate level in accredited Ontario universities. Winners receive a financial reward, plus a paid work placement with Hydro One.


## ELECTRICITY DISCOVERY CENTRE

September marked the first anniversary of our Electricity Discovery Centre, a mobile educational trailer that travels across the province to inform and educate the people of Ontario about energy consumption, electrical safety and the role Hydro One plays in their communities. Between September 2013 and September 2014, the Electricity Discovery Centre travelled more than 12,000 kilometres, attended 28 fairs and welcomed more than 27,500 visitors from across Ontario.

## CONFEDERATION COLLEGE PARTNERSHIP

In January, Hydro One announced funding for a pre-apprenticeship program with Confederation College. The $750,000 investment will support recruiting and training residents of Northern Ontario, with particular emphasis on peoples from Treaty 9 First Nations communities, in readiness for electrical technology and technician apprenticeships. The program will help build local trades capacity across Northern Ontario and is well aligned with the existing Hydro One College Consortium that focuses on curriculum development for electrical trades.

## LEONARD S. (TONY) MANDAMIN SCHOLARSHIP AWARD

In June, Hydro One recognized eight outstanding Aboriginal students as the 2014 recipients of the Leonard S. (Tony) Mandamin Scholarship Award. The scholarship was renamed in 2014 to recognize the achievements of the Honourable Justice Leonard S. (Tony) Mandamin, who was one of Ontario's first electrical engineering graduates of First Nations ancestry. The recipients of this award are offered a work term with Hydro One and receive financial support to aid in their academic studies.

## THE WILLIAM PEYTON HUBBARD MEMORIAL AWARD

In May, Hydro One awarded two outstanding black students with the William Peyton Hubbard Memorial Award for their studies in disciplines related to our industry. The award honours William Peyton Hubbard, Toronto's first black councillor and advocate of publicly owned electricity, who with Sir Adam Beck, brought electrical power to the people of Ontario.

## HYDRO ONE EMPLOYEES' AND PENSIONERS' CHARITY CAMPAIGN

The Company's charity campaign raised more than $1.3 million in 2014 for hundreds of charities across Ontario, surpassing 2013's contribution of $1.24 million. To date, more than 1,780 charities have benefited from the campaign.

# BOARD OF DIRECTORS
## (as at December 31, 2014)

**Sandra Pupatello**[6]
Chair of the Board of Directors, Hydro One Inc.

Director, Business Development and Global Markets for PwC, Canada

Chief Executive Officer WindsorEssex Economic Development Corporation

**Carmine Marcello**[6]
President and Chief Executive Officer, Hydro One Inc.

**Kathryn A. Bouey**[2,3,6]
President, TBG Strategic Services Inc.

Corporate Director

**George Cooke**[1,2,6]
President, Martello Associates Consulting

Chair of the Board of Directors of OMERS Administration Corporation

**Sally Daub**[1,4]
President and Chief Executive Officer, ViXS Systems Inc.

**Catherine Karakatsanis**[3,4,5]
Chief Operating Officer, Morrison Hershfield Group Inc.

**Bill Limbrick**[2,3]
Corporate Director

**Don MacKinnon**[1,4,5]
President, Power Workers' Union

**Tom Moss**[3,5]
Corporate Director

**Yezdi Pavri**[1,2,6]
Corporate Director

**Gale Rubenstein**[2,4,5,6]
Partner, Goodmans LLP

**Maureen Sabia**[1,3]
Non-Executive Chairman of the Board of Directors of Canadian Tire Corporation Limited

**John Wiersma**[3,5]
Corporate Director

**Carole Workman**[1,4]
Corporate Director

### Board Committees

1 *Audit, Finance and Pension Investment Committee* In May 2014, the Audit and Finance (AF) Committee amalgamated with the Investment-Pension (IP) Committee to form the Audit, Finance and Pension Investment Committee (AFPIC). The Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, financial risk exposures, financial compliance and ethics policies. In addition, the Committee assists the Board in fulfilling its oversight responsibilities in all matters related to the Hydro One Pension Plan including the Hydro One Pension Fund. The AF Committee met four times in 2014, the IP Committee met one time in 2014, and the AFPIC met five times in 2014.

2 *Corporate Governance and Human Resources Committee* In May 2014, the Corporate Governance (CG) Committee amalgamated with the Human Resources (HR) Committee to form the Corporate Governance and Human Resources Committee (CGHR). The Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandate of the Board and each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. In addition, the Committee is responsible for reviewing the appropriateness of the Company's current and future organizational structure, succession plans for senior corporate executive officers and divisional officers, the code of business conduct, and the performance and remuneration of senior executives, including recommending to the Board the remuneration of the President and CEO. The CG Committee met one time in 2014, the HR Committee met five times in 2014, and the CGHR Committee met nine times in 2014.

3 *Business Transformation Committee* The Business Transformation Committee is responsible for assisting the Board in its oversight responsibilities in all matters related to the Company's Cornerstone Project, the Advanced Distribution System (Smart Grid) and Continuous Innovation Strategy, and the planning, development and implementation of major transmission system or distribution projects, including projects described in the Corporation's Green Energy Implementation Plan. The Committee met fourteen times in 2014.

4 *Regulatory and Public Policy Committee* The Regulatory and Public Policy Committee monitors the Company's compliance with applicable regulatory requirements and legislation, and is responsible for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have a significant impact on the Company. The Committee oversees compliance programs, policies, standards and procedures and reviews the Company's proposals for rate applications, compliance actions and reports. The Committee met four times in 2014.

5 *Health, Safety and Environment Committee* The Health, Safety and Environment Committee is responsible for reviewing occupational health, safety and environment policies, standards, and programs, compliance with occupational health, safety and environmental legislation, policies and standards, and public health and safety issues. The Committee met three times in 2014.

6 *Strategy Committee* The Strategy Committee was established in May 2014 to assist the Board with matters relating to the Premier's Advisory Council on Government Assets. The Committee met four times in 2014.

### Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution, and telecom services.

### Hydro One Networks Inc.
Represents the majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

### Hydro One Brampton Networks Inc.
Distributes electricity to one of the fastest-growing urban centres in Canada, just 30 kilometres outside of Toronto.

### 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 province's electricity transmission grid.

### Hydro One Telecom Inc.
Markets our fibre-optic capacity to business customers. This business represents less than one per cent of our total assets.

## CORPORATE INFORMATION

### Corporate Address
483 Bay Street
Toronto, Ontario M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com

### Investor Relations
(416) 345-6867
investor.relations@HydroOne.com

Hydro One is a Securities and Exchange Commission (SEC) issuer in the United States. Hydro One's annual and quarterly filings, including Financial Statements, Management's Discussion and Analysis, Press Releases, Annual Information Form and Annual Report, can be found on SEDAR at www.sedar.com and on the United States' SEC website at www.sec.gov.

The documents can also be found on Hydro One's website at www.HydroOne.com under Investor Relations/Media.

### Media Inquiries
(416) 345-6868
1-877-506-7584

### Customer Inquiries
Power outage and emergency number:
1-800-434-1235

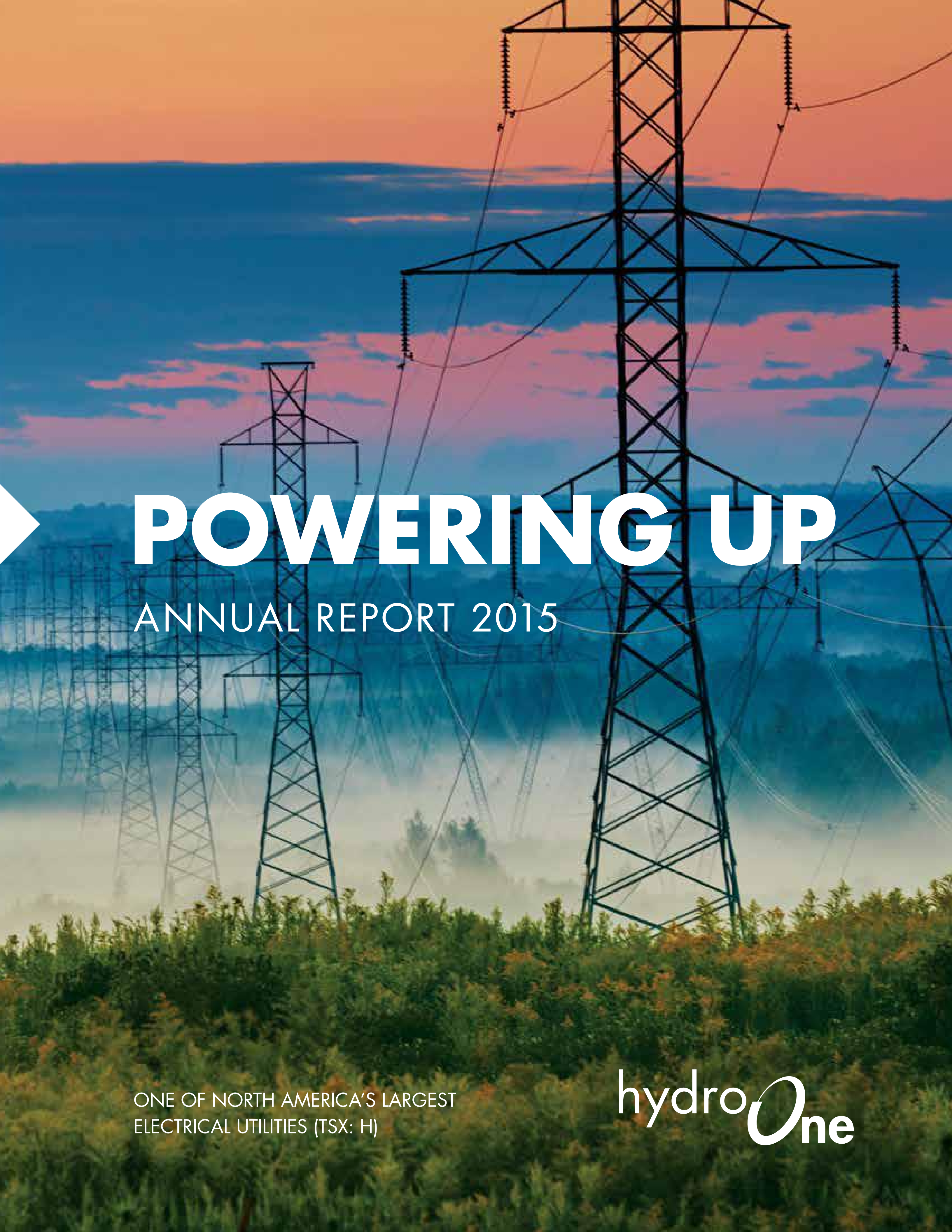
Residential, farm and small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

### Auditors
KPMG LLP

To learn more about what Hydro One is doing to deliver electricity, build for the future and keep the environment healthy, visit

**www.HydroOne.com**

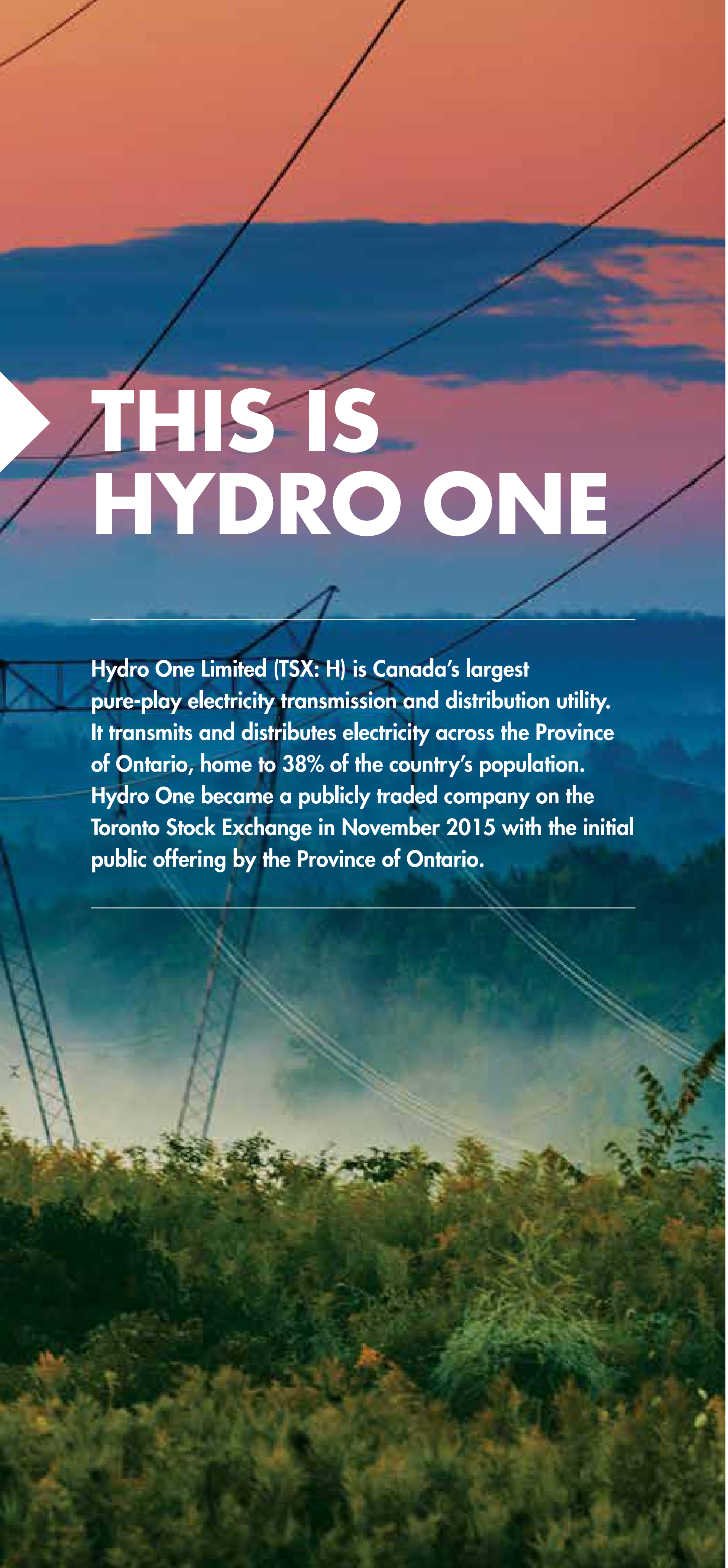


# POWERING UP

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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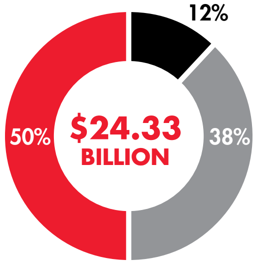
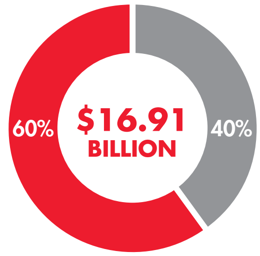
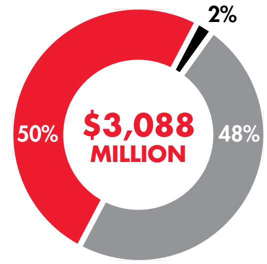
**TOTAL ASSETS**



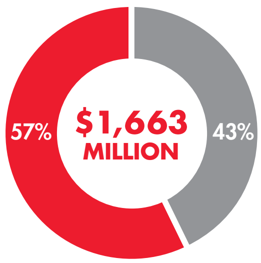

**RATE BASE**




**REVENUES (NET OF POWER COSTS)**




**CAPITAL INVESTMENTS**




**REGULATED EARNINGS BEFORE FINANCING CHARGES AND INCOME TAXES**[1]


Transmission

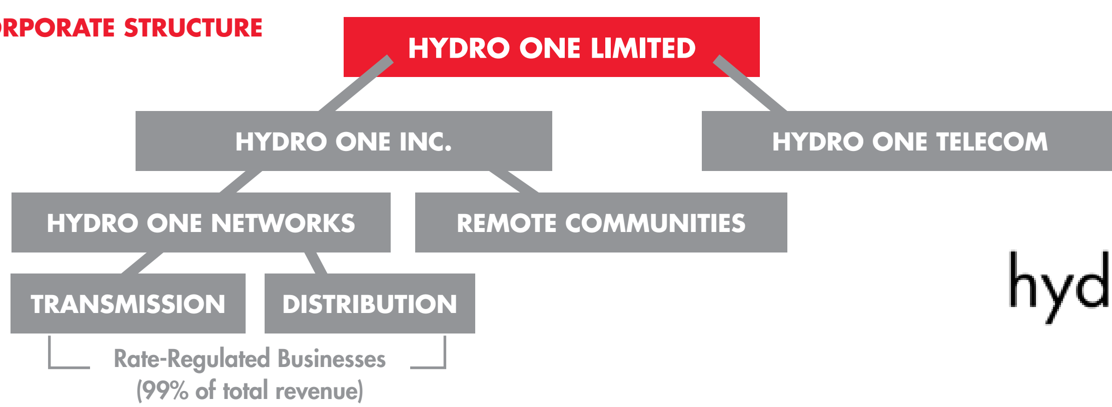
Distribution

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 Ontario 60-minute peak demand *(MW)* | **20,344** | 20,596 |
| Distribution – electricity distributed to Hydro One 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 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.

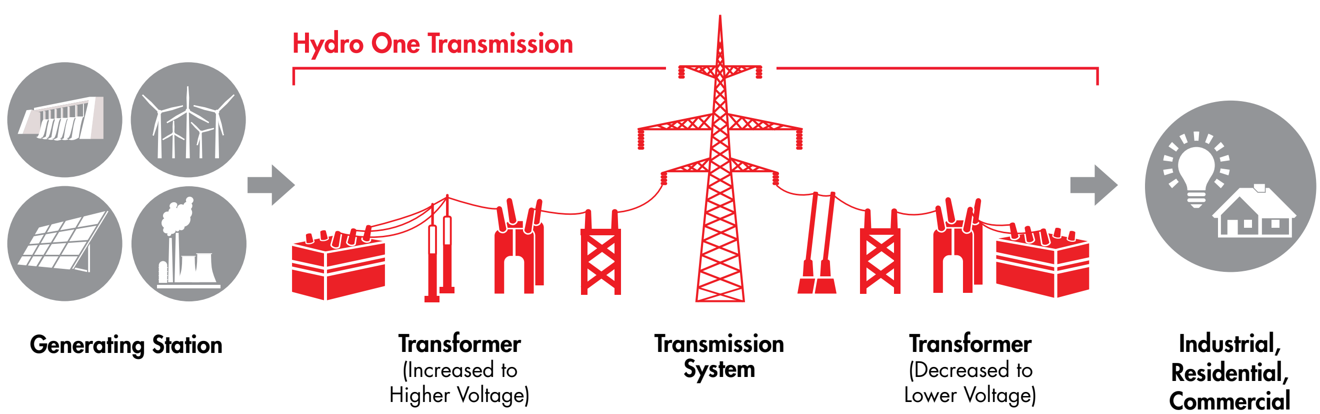
**TRANSMISSION STATIONS**
**292**

**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.**

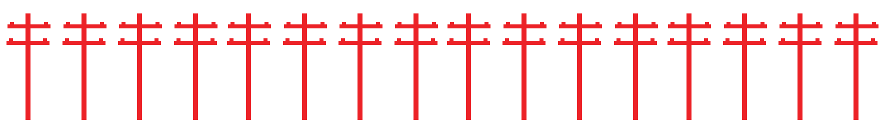
As Hydro One operates in both rural and urban centres across Ontario, customers benefit from our integrated planning and the coordinated operations of our distribution and transmission systems and workforce.

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.

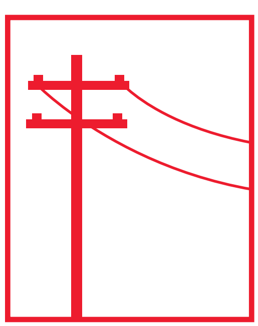
**Hydro One Remote Communities Inc.** operates and maintains the generation and distribution assets used to supply electricity to 21 remote communities across northern Ontario that are not connected to the electricity transmission grid.

## HYDRO ONE HAS A LARGELY RURAL AND SUBURBAN FOOTPRINT

**1.3 MILLION CUSTOMERS**



**1.6 MILLION POLES**

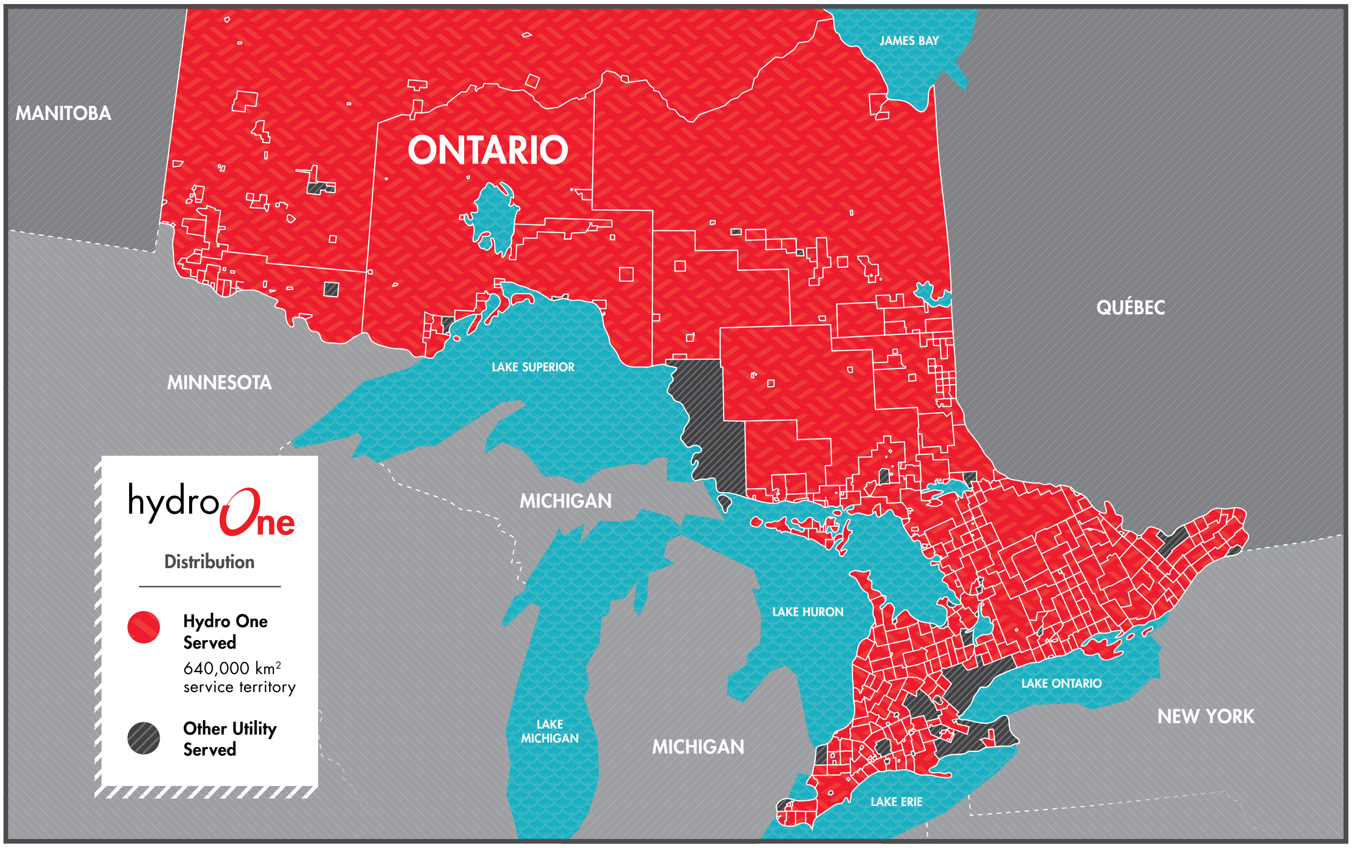


**CIRCUIT KILOMETRES OF LOWER-VOLTAGE LINES**

**123,000**

**DISTRIBUTION AND REGULATION STATIONS**

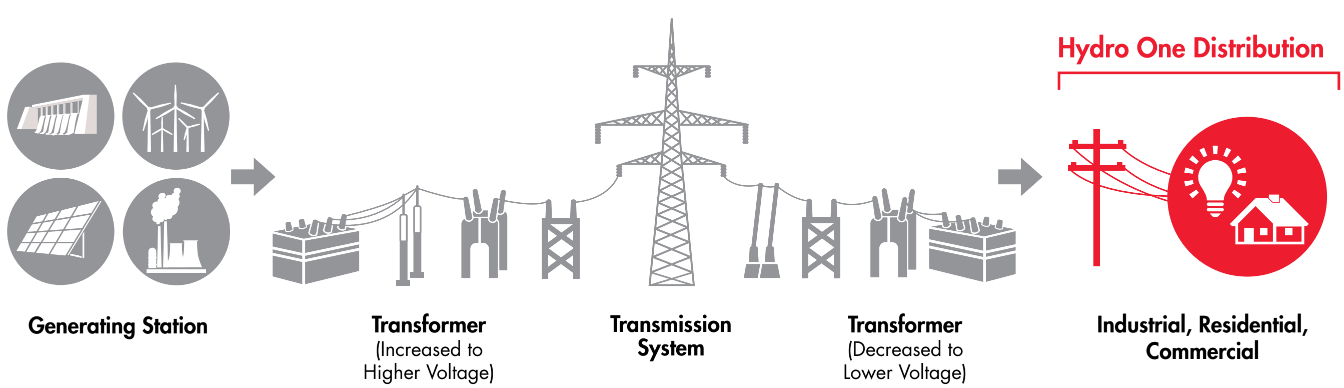
**c. 1,000**




| | 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.

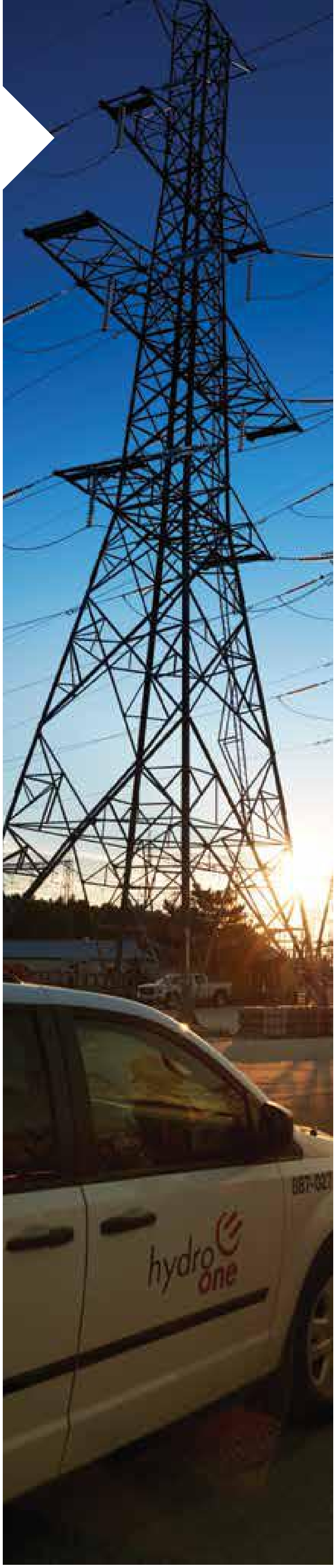
### *Scholarship Programs*

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.***

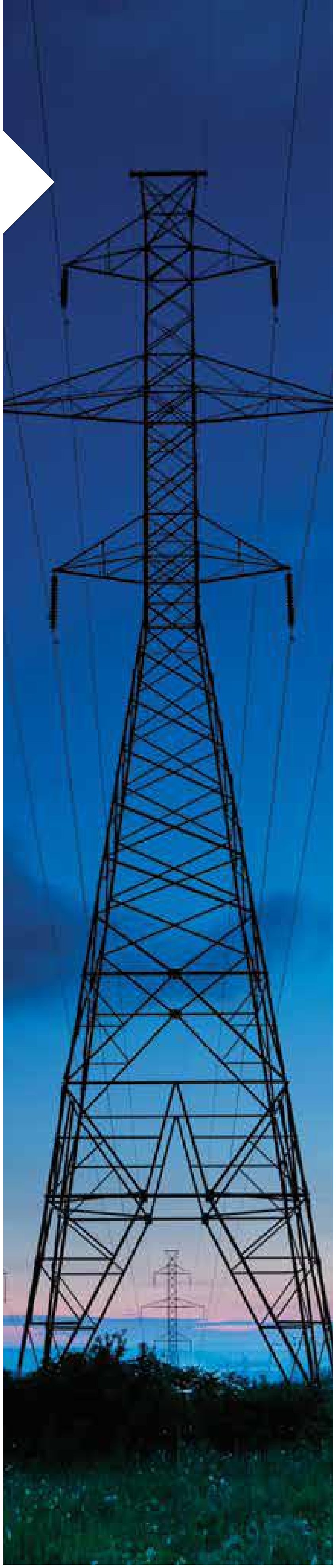
## BOARD OF DIRECTORS AND COMMITTEES

★ = 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**

hydro One



# 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*<br>*(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

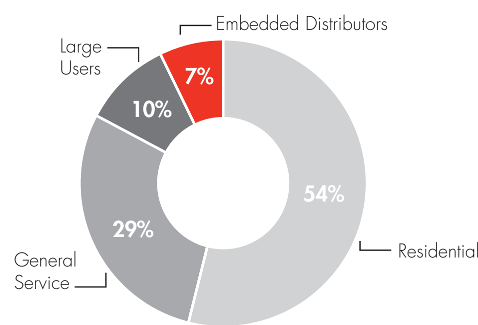
Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 96% of Ontario's transmission capacity. The Transmission Business consists of the transmission system operated by Hydro One Inc.'s subsidiary, Hydro One Networks Inc. (Hydro 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*<br>*(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 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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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<br>Life expectancy at 65 for a member currently at | | | | December 31, 2014<br>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*<br>*(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*<br>*(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*<br>*(millions of Canadian dollars)* | Pension Benefits 2015 | Pension Benefits 2014 | Post-Retirement and Post-Employment Benefits 2015 | Post-Retirement and Post-Employment Benefits 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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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*<br>*(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

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**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

hydro One

# POWERING FORWARD

## 2016 ANNUAL REPORT

ONE OF NORTH AMERICA'S LARGEST ELECTRIC UTILITIES (TSX: H)

**Hydro One Limited is Canada's largest pure-play electric transmission and distribution utility with $25 billion in assets and annual revenues of over $6.5 billion. It transmits and distributes electricity safely and reliably across the Province of Ontario, home to 38 percent of the country's population.**

Hydro One owns and operates a 30,000 circuit km high-voltage transmission network transmitting 98 percent of Ontario s electric capacity, and a 123,000 circuit km lower voltage distribution network serving 75 percent of the geography of the province and more than 1.3 million residential and business customers. Hydro One Limited became a public company coincident with its initial public offering in November 2015, and its common shares are listed on the Toronto Stock Exchange (TSX: H).

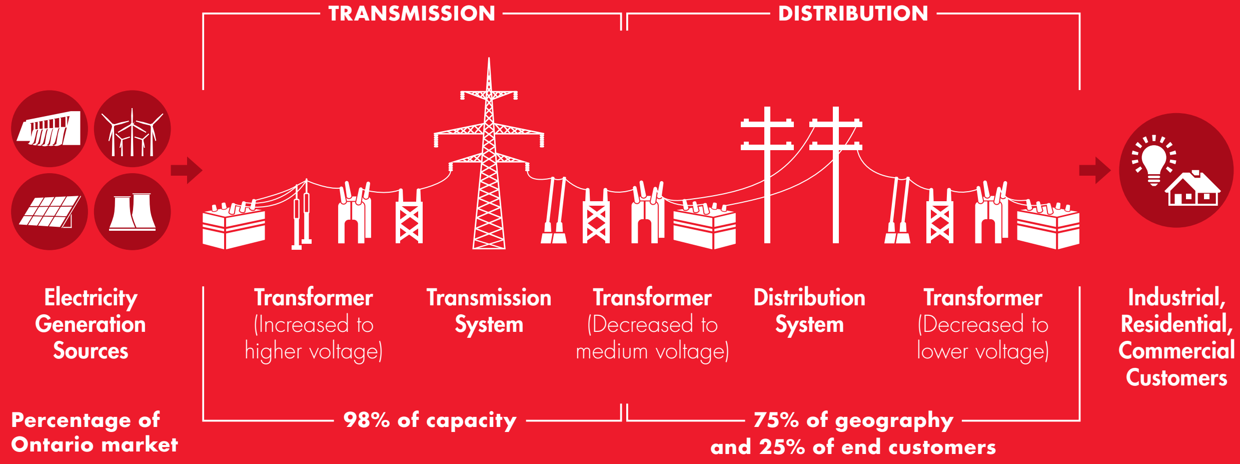
# HYDRO ONE'S **BUSINESS**

| **YEAR ENDED DECEMBER 31,** (CAD $ millions, except per share amounts) | **2016** | **2015** |
|---|---|---|
| Revenues | **$ 6,552** | $ 6,538 |
| Purchased power | **3,427** | 3,450 |
| **Revenues (net of purchased power)** | **3,125** | 3,088 |
| Operation, maintenance and administration | **1,069** | 1,135 |
| Depreciation and amortization | **778** | 759 |
| Income before financing charges and income tax expense | **1278** | 1,194 |
| Financing charges | **393** | 376 |
| Income tax expense | **139** | 105 |
| **Net income attributable to common shareholders** | **721** | 690 |
| Diluted earnings per common share | **1.21** | 1.39 |
| Adjusted diluted earnings per common share [1] | **1.21** | 1.16 |
| Net cash from (used in) operating activities | **1,656** | (1,253) |
| Adjusted net cash from operating activities [2] | **1,656** | 1,557 |
| Capital investments | **1,697** | 1,663 |
| Transmission – average monthly Ontario 60-minute peak demand *(MW)* | **20,690** | 20,344 |
| Distribution – electricity distributed to Hydro One customers *(GWh)* | **26,289** | 28,764 |

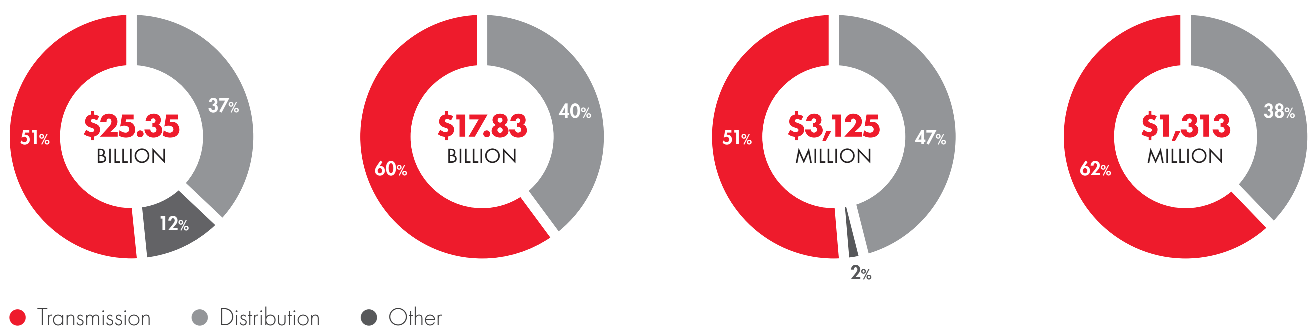
[1] 2015 Adjusted earnings per share (EPS) is calculated using the number of common shares outstanding at December 31, 2016

[2] 2015 amount excludes the $2,810 million non-cash impact of IPO-related adjustments

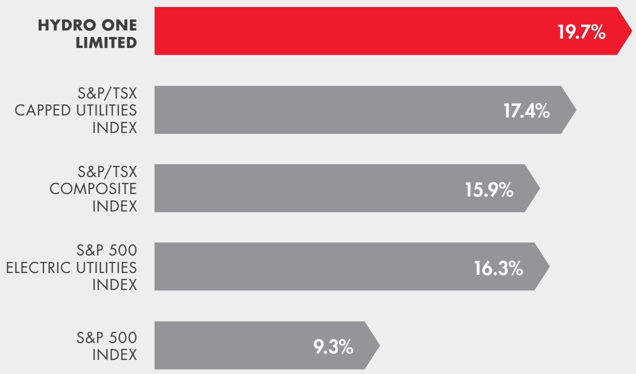
## HYDRO ONE'S ROLE
IN THE ELECTRIC POWER SYSTEM




**TOTAL ASSETS** | **RATE BASE** | **REVENUES** (NET OF PURCHASED POWER COSTS) | **REGULATED EARNINGS BEFORE FINANCING CHARGES AND INCOME TAXES**




### TOTAL SHAREHOLDER RETURN*
NOVEMBER 5, 2015 IPO TO DECEMBER 31, 2016




*Source: Bloomberg and S&P

## CONTENTS

> **"Hydro One has achieved much over this past year while making significant progress in laying the foundation and building the organizational momentum to deliver increasing value for its customers and shareholders in the years to come."**

# A MESSAGE FROM **THE CHAIR OF THE BOARD**

Dear fellow shareholders,

2016 was Hydro One's first full year as a public company, and its evolution to a more broadly owned and customer-focused organization is well underway. The company has achieved much over this past year, including executing its 2016 financial and operating plans and generating total shareholder return of 19.7% since the November 2015 initial public offering. It has also made significant progress in laying the foundation to deliver increasing value for its customers and shareholders in the years to come.

One of President and Chief Executive Officer Mayo Schmidt's key objectives over the past year was to significantly strengthen the company's senior leadership team, and in that regard we now have new executives heading Hydro One's operations, customer service, legal, and strategy functions. Each of these individuals has brought significant experience and capabilities to Hydro One, and the Board of Directors is very confident that we now have in place the depth and breadth of leadership expertise that will further accelerate the company's evolution.

In April 2016, the Province of Ontario sold an additional 15% of its stake in Hydro One to the public in a very successful secondary offering. This followed the November 2015 initial public offering of the shares of Hydro One, and served to double the public float of the company to 30% of shares outstanding while at the same time measurably increasing the trading volume and liquidity of the shares. This transaction was not dilutive to our existing public shareholders, and was another step by the Province towards its stated goal of reducing its ownership of Hydro One to 40%.

While the Province of Ontario remains a significant shareholder of Hydro One, the autonomy of the company and independence of our Board of Directors is enshrined in a governance agreement between Hydro One and the Province. This governance agreement was executed in advance of last year's initial public offering and has operated as designed to ensure that the company is governed as an independent commercial entity with the Province's role limited to that of a shareholder.

I would like to recognize my fellow Board members for their service over this busy period of change. Our Board is comprised of a diverse and accomplished group of proven leaders, each of whom is very committed to the success of Hydro One and the highest standards of corporate governance. The Board has been highly engaged with Mayo Schmidt and his leadership team in defining the strategy for the organization and charting the path forward over the course of the next few years.

I would also like to acknowledge the hard work and commitment of the more than 5,500 regular employees of Hydro One. This team of dedicated professionals works tirelessly -- often around the clock and in potentially hazardous weather and conditions -- to ensure that electric power is transmitted and distributed safely, reliably and cost-effectively to the millions of citizens of Ontario and the communities in which they live and work.

Thank you for your investment and continued support,

**DAVID F. DENISON, O.C.**
*Chair of the Board*
Hydro One Limited

"We have assembled a team of talented and deeply experienced leaders who are dedicated to transforming Hydro One into a more disciplined, customer-focused and commercially oriented electric transmission and distribution service provider."

# A MESSAGE FROM **THE PRESIDENT AND CEO**

Dear fellow shareholders,

This is a new era at Hydro One. 2016 was a transformative year as we embarked on our journey from good to great. In this first full year as a public company, we undertook a company-wide systematic review of our business. Through this intensive process, we identified a number of initiatives, metrics and targets that will enable us to drive greater efficiency and effectiveness across customer service, operations, procurement, network planning, capital deployment and administration.

Accordingly, we have assembled a team of talented and deeply experienced leaders who are dedicated to transforming Hydro One into a more disciplined, customer-focused and commercially oriented electric transmission and distribution service provider. We are becoming significantly more customer and performance driven by focusing on company-wide accountability, productivity, and efficiency while also engaging more proactively with our communities and First Nations and Métis partners.

Many Ontarians feel the pressure of increases to their electricity bills, so we are doing our part to keep Hydro One's portion of the bill as low as possible. We are also providing customers with meaningful conservation programs so they can take greater control of their consumption and manage their bills. Part of this move involves information technology investments that enable the shift from paper-based systems to increasingly mobile, online and paperless technologies.

Hydro One's employees have embraced our transformational journey to becoming a commercial enterprise, one focused on delivering value for customers and shareholders. This transformation is central to our actions and strategies, and is enshrined in all that we endeavour to achieve. As we move the organization forward and modernize Ontario's electrical grid, I believe that we have multiple opportunities to create increasing value for our customers and shareholders alike.

While we are fortunate to have a strong foundation for growth upon which to build, we are also aware that there are opportunities for us to enhance customer service and improve our execution capabilities across the business. We also appreciate the criticality of accelerating the pace of upgrading Ontario's aging electric power system and the significant infrastructure investment that is needed to build and maintain a strong, modern and reliable grid.

We made important progress this year on the regulatory front, where we now have a plan with a clear line of sight to the imminent transition from a cost of service-based regulatory model to a more dynamic performance-based, customer-focused regulatory model. We are fully engaged and gaining traction on this front in both segments of our regulated business. We expect to complete the transition to a performance-based regulatory framework in our distribution segment in early 2018 and in our transmission segment in early 2019.

In addition to the significant value we intend to create in improving the performance of our substantial existing operations, there is also value to be created in continuing to lead the consolidation of what is still a fragmented system of electric utility assets in Ontario. As such, during 2016 we significantly stepped up the rigour and capabilities around how we acquire and integrate other electric utilities. Our successful integration of the Haldimand and Woodstock municipal utilities is a good indicator of things to come. During the year, we also completed the acquisition of Great Lakes Power Transmission and announced the acquisition of Orillia Power Distribution, two regulated electric utilities in Ontario which further add to our leadership position.

My thanks go out to the thousands of Hydro One employees across Ontario for embracing this transformational journey and their unwavering commitment to our customers. I also extend my appreciation to our Board of Directors for its support and confidence in management.

The future is bright and we will continue to power forward,

Mayo Schmidt

**MAYO SCHMIDT**
*President and Chief Executive Officer*
Hydro One Limited

**IN 2016, HYDRO ONE COMPLETED THE PURCHASE OF GREAT LAKES POWER TRANSMISSION, THE SECOND LARGEST ELECTRICITY TRANSMITTER IN ONTARIO. THIS ACQUISITION INCREASED HYDRO ONE'S TRANSMISSION CAPACITY IN ONTARIO TO 98%, WHILE IMPROVING THE COMPANY'S ABILITY TO CONNECT GENERATORS IN NORTHERN ONTARIO TO ELECTRICITY DEMAND IN SOUTHERN ONTARIO.**

# ELECTRIC TRANSMISSION SEGMENT

The scale of Hydro One's transmission operations increased during 2016 to approximately 30,000 circuit-kilometres of high-voltage lines. Hydro One transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar generation sources to local distribution companies and to directly connected industrial customers across Ontario.

**Hydro One's transmission assets can be divided into three main categories:**

**Transmission stations**
Used for the delivery of power, voltage transformation and switching, the stations serve as connection points for both customers and generators.

**Transmission lines**
Bulk transmission lines deliver 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.

**Network operations**
The Ontario Grid Control Centre manages all of Hydro One's transmission and sub-transmission operations.

**During 2016, capital investments in Hydro One's transmission segment totaled $988 million, including expenditures on the following projects:**

### TORONTO MIDTOWN TRANSMISSION REINFORCEMENT PROJECT

In 2016, Hydro One substantially completed work on the $118 million Toronto Midtown Transmission Reinforcement Project which refurbished the existing transmission infrastructure that serves midtown Toronto and areas to the west. This five-year project replaced 14,500 metres of transmission cables and provides 100 megawatts of additional capacity to serve the local distribution company and its customers.

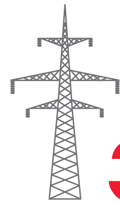
### GUELPH AREA TRANSMISSION REFURBISHMENT PROJECT

Hydro One substantially completed the $87 million Guelph Area Transmission Refurbishment Project that will help meet the electricity needs of the growing southwestern Ontario region. The project included upgrading a five-kilometre section of existing transmission lines, and installing new transformer and switching equipment at the transformer station. More than 340 construction professionals were involved in the construction phase of the project.

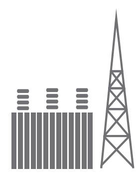
### COLLABORATION WITH LONDON HYDRO

Hydro One entered into a collaborative investment with London Hydro to modernize the equipment in Hydro One's Nelson Transformer Station. Hydro One identified a need to replace aging equipment and London Hydro contributed financially for a voltage conversion of the station to be consistent with the other six local transformer stations, allowing the entire London Hydro system to be interconnected. The project will also increase the reliability of supply to an important station that serves much of downtown London.

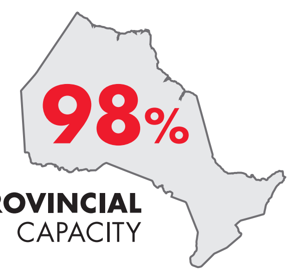
These projects together with many others underway ensure that Ontarians continue to receive a safe, reliable supply of electricity now, and for years to come.



**30,000**
**CIRCUIT KILOMETRES**
OF HIGH-VOLTAGE LINES



**306**
**TRANSMISSION**
STATIONS




**PROVINCIAL**
CAPACITY

## ONE OF NORTH AMERICA'S LARGEST ELECTRIC POWER TRANSMITTERS

Photo courtesy of Brian Pieters Photography
www.pietersphoto.com

**HYDRO ONE'S 5,500 SKILLED AND DEDICATED EMPLOYEES SERVE 1.3 MILLION VALUED RESIDENTIAL AND BUSINESS CUSTOMERS ACROSS ONTARIO. HYDRO ONE IS THE PROVINCE'S LARGEST LOCAL ELECTRIC POWER DISTRIBUTION COMPANY WITH APPROXIMATELY 123,000 CIRCUIT KILOMETRES OF POWER LINES.**

# ELECTRIC DISTRIBUTION SEGMENT

Operating in rural, suburban and urban communities spread across the province of Ontario, home to 38 percent of the population of Canada, Hydro One possesses significant economies of scale and brings to bear a strong commitment to ensuring a modern and reliable local electricity system for its 1.3 million customers. This commitment also includes serving customers in 21 remote communities spread across the far reaches of northern Ontario that are not connected to the electricity transmission grid.

### CUSTOMER CONSULTATION

In mid-2016, Hydro One announced a province-wide consultation process to seek input from its customers on the development of a five-year rate plan that will help shape future investments in Hydro One's electric distribution system. The goal of the consultation was to better understand how Hydro One's customers' needs are being met by the current system, and the types of reliability and service improvements customers would value most. This included addressing aging electricity infrastructure, system repairs and responding to power outages, power quality and costs, as well as new products, services and web-enabled tools to make it easier for customers to do business with Hydro One.

The feedback influenced detailed plans that the company will submit to the Ontario Energy Board, who will ultimately determine the investments and rate plans for Hydro One's local distribution segment for the 2018 through 2022 period.

### ACQUISITION OF ORILLIA POWER

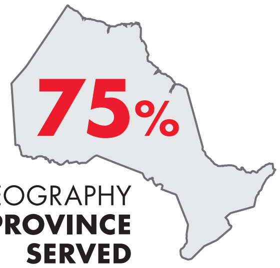
In August 2016, Hydro One announced that it reached a definitive agreement to acquire Orillia Power Distribution Corporation in a transaction valued at over $41 million. Hydro One will integrate into its operations approximately 14,000 customers located in Simcoe County, home to a population of more than 30,000 and part of the Huronia region of Central Ontario.

Hydro One's current service territory includes the areas surrounding the City of Orillia and this acquisition enables Hydro One to realize operational synergies over time. After closing, Hydro One also intends to construct several grid control and operating facilities in Orillia. The acquisition is conditional upon the satisfaction of customary closing conditions and approval of the Ontario Energy Board.

### SERVING MANITOULIN ISLAND

In October 2016, Hydro One announced that a new distribution station will be built to serve customers on Manitoulin Island, located in northern Ontario on Lake Huron. The new distribution station will replace the Little Current Distribution Station, which was originally built in 1950, and will help improve reliability and increase capacity for the approximately 10,000 customers who live on Manitoulin Island.

**123,000**
**CIRCUIT KILOMETRES**
OF LOCAL DISTRIBUTION LINES




GEOGRAPHY
OF **PROVINCE**
**SERVED**

**1.3M**
**RESIDENTIAL & BUSINESS CUSTOMERS**
ACROSS ONTARIO

**ONTARIO'S LARGEST LOCAL ELECTRIC POWER DISTRIBUTION COMPANY**


**SERVING CUSTOMERS AND COMMUNITIES RELIABLY AND SAFELY**

# SERVING
# CUSTOMERS & COMMUNITIES

| | | |
|---|---|---|
| CUSTOMER SERVICE | RELIABILITY | SAFETY |
| FIRST NATIONS PARTNERSHIPS | SUSTAINABILITY | DIVERSITY |

Throughout 2016, Hydro One's skilled and dedicated employees responded 24 hours a day, seven days a week to quickly and safely restore power for customers through often extremely challenging weather, terrain and circumstances. Hydro One also continued to provide new and enhanced programs and services to further define the company's commitment to customer service and energy conservation.

## PROACTIVE OUTAGE ALERTS

In early 2016, Hydro One was the first utility in Canada to offer customers proactive outage alerts. Customers who register for this service receive personalized email or text alerts about outages that may affect their homes, cottages, farms or small businesses, as well as information on estimated times of restoration. Since launching the program, Hydro One has sent hundreds of thousands of proactive alerts to customers. This service is an extension of Hydro One's existing suite of outage communication tools, which includes online outage maps and smartphone apps.

## GET LOCAL IN FIRST NATIONS COMMUNITIES

Hydro One began to offer a new service model in First Nations and Métis communities which focuses on local, face-to-face interactions to ensure customers are informed of and have access to all of the conservation and assistance programs the company offers. Meeting with Chiefs and Councils, representatives from Hydro One's Customer Service team visit communities throughout the province and conduct information-sharing sessions with customers.

*For further information on Hydro One's commitments to customers go to*
▶ HydroOne.com/Commitments

## FARM RAPID RESPONSE TEAM

Hydro One announced the launch of its Farm Rapid Response Team that assists the company's 13,000 farming customers to identify, assess and mitigate on-farm electrical issues. This new approach better serves the needs of Hydro One's farming customers and was developed in partnership with the Ontario Federation of Agriculture. This streamlined process also provides Hydro One's farming customers a single, specialized point of contact to better assist with their specific on-farm concerns.

## PAPERLESS BILLING AND HIGH USAGE ALERTS

In late 2016, Hydro One launched paperless billing notifications and high usage alerts to provide customers with more visibility and control over their accounts and energy use. With billing notifications, customers sign up to receive paperless billing together with personalized insights and program promotions, which also provide a new online self-service channel for customers as an alternative to contacting the call centre. With high usage alerts, customers receive emails or text messages if their usage during a billing period is trending higher than a predefined threshold. Customers also receive guidance on how they can adjust their energy use before the end of the billing period. Through the enhanced web portal, customers can also easily find more information about their energy use, as well as explore a wide range of energy tips and conservation programs provided by Hydro One.

## COMMUNITY INVESTMENT

Throughout 2016, Hydro One committed millions of dollars in donations and sponsorships to communities it serves across Ontario. The contributions supported community projects such as the Markstay outdoor ice rink roof-building project for the local municipality, benefiting the community's local youth. Other community initiatives include the company's partnership with Right to Play's Promoting Life-Skills in Aboriginal Youth program, a non-profit organization that aims to deliver safe, fun and educational programming to Aboriginal youth.

# TRANSMITTING AND DELIVERING SOME OF THE CLEANEST ELECTRIC POWER IN NORTH AMERICA

**AS A STEWARD OF THE GRID, HYDRO ONE IS FOCUSED ON TRANSMITTING AND DELIVERING SAFE, CLEAN AND SUSTAINABLE ENERGY. THIS YEAR THE COMPANY PRODUCED ITS FIRST CORPORATE SOCIAL RESPONSIBILITY REPORT, ONE WHICH ADHERES TO THE GUIDELINES FOR THE G4 GLOBAL REPORTING INITIATIVE AND IS PART OF A CONTINUED EFFORT BY THE COMPANY TO ENHANCE THE TRANSPARENCY, ACCOUNTABILITY AND LINE OF SIGHT TO ITS SUSTAINABLE OPERATIONS.**

## ENVIRONMENTAL SUSTAINABILITY

### HEBER DOWN CONSERVATION AREA

Hydro One's Forestry team partnered with the Central Lake Ontario Conservation Authority and neighbouring utilities to mitigate the spread of Phragmites, an invasive species, on 3,500 square metres of a right-of-way corridor in the Heber Down Conservation Area. Challenging and costly to remove, such invasive species threaten lakes, rivers and forests. Together with a local contractor and using a variety of control methods based on location, density and surrounding vegetation of each area, the company began work on eliminating the invasive species from its right-of-way. With thousands of kilometres of transmission line corridors crossing the province, the company has taken a leadership role in engaging with local stakeholders, taking a proactive approach to land management and pooling community resources to manage the spread of invasive species.

### VEGETATION MANAGEMENT

To ensure the continued safe operation of Hydro One's transmission and distribution lines, the company conducts province-wide vegetation management operations to maintain reliability across the system. As part of the company's ongoing commitment to local communities, Hydro One has consulted with conservation authorities and is working with local seed distributors to develop and test pollinator-friendly seed mixes. Pollinators include various forms of bees, wasps, ants, flies, moths, beetles, bats and birds. These species feed on nectar and pollen from plants and their populations in Ontario are generally in decline due to habitat loss, disease, pesticide use and climate change. To mitigate this, Hydro One is working to incorporate pollinator-friendly seed as part of its vegetation management work in appropriate areas as an alternative to grass seed. Locally, this work supports provincial initiatives like the Pollinator Health Action Plan developed by the Ontario Ministry of Agriculture, Food and Rural Affairs.

### CORPORATE KNIGHT'S BEST 50 CORPORATE CITIZENS

Hydro One was ranked as the top utility in the 15th annual ranking of the 2015 Corporate Knights Canada's Best 50 Corporate Citizens. The Best 50 Corporate Citizens in Canada ranking assesses a broad range of Canadian enterprises on a set of 12 sustainability metrics, including carbon, water and waste productivity, percent of taxes paid, leadership gender diversity, innovation, health and safety performance, and pension fund quality. Being recognized as one of Canada's Best 50 Corporate Citizens is a testament to Hydro One's core values and demonstrates that the company continues to develop a strong culture of sustainability and corporate responsibility. Customers, investors and citizens of Ontario should expect that Hydro One will power forward in its responsible leadership on Corporate Citizenship in Canada.

*For further information on Hydro One's commitments to the environment, go to*
▶ HydroOne.com/OurCommitment

# CORPORATE GOVERNANCE
# OVERVIEW

★ CHAIR ● MEMBER

| BOARD OF DIRECTORS AND COMMITTEES | 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 | | | ● | ★ |
| James Hinds | ● | | | ● |
| Kathryn Jackson | | ● | | ● |
| Roberta Jamieson | ● | | | ● |
| Frances Lankin | ● | ● | | |
| Philip Orsino | ★ | ● | | |
| Jane Peverett | | ★ | ● | |
| Gale Rubenstein | | | ● | ● |

Hydro One and its independent Board of Directors 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 shareholders as well as customers and promotes and strengthens relationships with employees, the communities in which the company operates and other stakeholders of the company. The Board of Directors is firmly supported in these commitments by a governance agreement between Hydro One and the Province of Ontario, which was executed in advance of the November 2015 initial public offering of the company and assures that the Province's role is limited to that of a shareholder and not a manager of the business.

Hydro One's Board of Directors is composed of a diverse and accomplished group of independent, 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 of corporate governance, and regularly reviews the company's governance practices in response to changing governance expectations and regulations. The Company's practices are fully aligned with the rules and regulations issued by Canadian Securities Administrators and the Toronto Stock Exchange, including national corporate governance guidelines and related disclosure requirements.

## HYDRO ONE'S GOOD GOVERNANCE PRACTICES

| | | |
|---|---|---|
| FULLY INDEPENDENT BOARD (EXCLUDING CEO) | 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 |
| SEPARATE BOARD CHAIR AND CEO | MAJORITY VOTING FOR DIRECTORS | GOVERNANCE AGREEMENT WITH PROVINCE |

*For a complete description of Hydro One's corporate governance structure and practices and individual director biographical information, go to*
▶ HydroOne.com/Investors

# TEN REASONS TO INVEST IN HYDRO ONE

1

One of the largest pure play electric utilities in North America, with significant scale and a leadership position in Canada's most populated province

2

Unique combination of electric transmission and local distribution, with no material exposure to commodity prices

3

Business is 99 percent regulated and operates in a stable, transparent and collaborative rate-regulated environment

4

Consistent rate base growth expected under multi-year capital investment program to upgrade aging electric power system infrastructure

5

Strong governance structure and a fully independent Board allow company to operate autonomously, transform its culture and drive shareholder value creation on multiple fronts

6

Timing of operational transformation coincident with transition to Ontario's incentive based regulatory framework expected to create value for both customers and shareholders

7

Proven management team with demonstrated experience in transforming organizations, accelerating performance and creating significant shareholder value

8

Attractive dividend yield with 70 – 80 percent target payout ratio and opportunity for growth with rate base expansion, efficiency realization and continued consolidation

9

Strong 'A'-rated investment grade balance sheet with one of the highest-quality credit profiles in the North American utility sector

10

**A unique opportunity to participate in the transformation of a premium, large-scale utility**

hydro One

# 2016 FINANCIAL REPORT

# Management's Discussion and Analysis

*For the years ended December 31, 2016 and 2015*

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, 2016. 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, 2016, based on information available to management as of February 9, 2017.

The comparative 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. See further details in section "Other Developments – Change in Hydro One Ownership Structure".

## Consolidated Financial Highlights And Statistics

| *Year ended December 31*<br>*(millions of dollars, except as otherwise noted)* | 2016 | 2015 | Change |
|---|---|---|---|
| Revenues | 6,552 | 6,538 | 0.2% |
| Purchased power | 3,427 | 3,450 | (0.7%) |
| Revenues, net of purchased power | 3,125 | 3,088 | 1.2% |
| Operation, maintenance and administration costs | 1,069 | 1,135 | (5.8%) |
| Depreciation and amortization | 778 | 759 | 2.5% |
| Financing charges | 393 | 376 | 4.5% |
| Income tax expense | 139 | 105 | 32.4% |
| Net income attributable to common shareholders of Hydro One | 721 | 690 | 4.5% |
| Basic earnings per common share (EPS) | $ 1.21 | $ 1.39 | (12.9%) |
| Diluted EPS | $ 1.21 | $ 1.39 | (12.9%) |
| Basic pro forma adjusted non-GAAP EPS (Adjusted EPS)[1] | $ 1.21 | $ 1.16 | 4.5% |
| Diluted Adjusted EPS[1] | $ 1.21 | $ 1.16 | 4.5% |
| Net cash from (used in) operating activities | 1,656 | (1,248) | 232.7% |
| Adjusted net cash from operating activities[1] | 1,656 | 1,562 | 6.0% |
| Funds from (used in) operations (FFO)[1] | 1,494 | (1,479) | 201.0% |
| Adjusted FFO[1] | 1,494 | 1,331 | 12.2% |
| Capital investments | 1,697 | 1,663 | 2.0% |
| Assets placed in-service | 1,605 | 1,476 | 8.7% |
| Transmission: Average monthly Ontario 60-minute peak demand *(MW)* | 20,690 | 20,344 | 1.7% |
| Distribution: Electricity distributed to Hydro One customers *(GWh)* | 26,289 | 28,764 | (8.6%) |

| *December 31* | 2016 | 2015 |
|---|---|---|
| Debt to capitalization ratio[2] | 52.6% | 50.7% |

[1] See section "Non-GAAP Measures" for description and reconciliation of Adjusted 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 and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

## Overview

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its wholly owned subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and an approximately 123,000 circuit km low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

### Transmission Segment

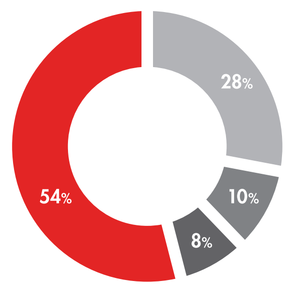
Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board (OEB). The Transmission Business consists of the transmission system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP (Great Lakes Power)), as well as 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 OEB. The transmission business represented approximately 51% of the Company's total assets as at December 31, 2016, and approximately 51% of its 2016 revenues, net of purchased power.

| | 2016 | 2015 |
|---|---|---|
| Electricity transmitted[1] *(MWh)* | 136,989,747 | 137,011,780 |
| Transmission lines spanning the province *(circuit-kilometres)* | 30,259 | 29,355 |
| Rate base *(millions of dollars)* | 10,775 | 10,175 |
| Capital investments *(millions of dollars)* | 988 | 943 |
| Assets placed in-service *(millions of dollars)* | 937 | 696 |

[1] Electricity transmitted represents total electricity transmission in Ontario by all transmitters.

### Distribution Segment

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 are approved by the OEB. The distribution business represented approximately 37% of the Company's total assets as at December 31, 2016, and approximately 47% of its 2016 revenues, net of purchased power.




| | 2016 | 2015 |
|---|---|---|
| Electricity distributed to Hydro One customers *(GWh)* | 26,289 | 28,764 |
| Electricity distributed through Hydro One lines *(GWh)*[1] | 37,394 | 40,721 |
| Distribution lines spanning the province *(circuit-kilometres)* | 122,599 | 123,425 |
| Distribution customers *(number of customers)* | 1,355,302 | 1,347,231 |
| Rate base *(millions of dollars)* | 7,056 | 6,739 |
| Capital investments *(millions of dollars)* | 703 | 711 |
| Assets placed in-service *(millions of dollars)* | 662 | 775 |

[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 Segment

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 broadband 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, 2016, and approximately 2% of its 2016 revenues, net of purchased power.

# 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 power 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 the 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 revenues such as charges for late payments.

## Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery 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 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 and amortization 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 and short-term borrowings, gains and losses on interest rate swap agreements, net of interest earned on short-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.

# Results of Operations

## Net Income

Net income attributable to common shareholders for the year ended December 31, 2016 was $721 million, an increase of 4.5% from the prior year. Earnings were positively affected by lower OM&A and higher revenues net of purchased power. These positive effects were partly offset by non-recurring items related to the Company's IPO in 2015, namely an increase in the effective tax rate primarily driven by IPO-related tax benefit of $19 million recorded in 2015 and divestiture of Hydro One Brampton Inc. (Hydro One Brampton) in 2015. Excluding these IPO-related effects, net income increased by 10.9%.

## Basic EPS and Adjusted Basic EPS

Basic EPS was $1.21 in 2016 (2015 – $1.39). Basic EPS is significantly affected by the weighted average number of shares in issue being different from last year due to the effects of the IPO, and is the most significant reason for the lower EPS compared to last year.

Adjusted Basic EPS, which adjusts for the inconsistent number of shares in issue, was $1.21 in 2016 (2015 – $1.16), driven by increased net income compared to last year. See section "Non-GAAP Measures" for description of Adjusted EPS.

## Revenues

| *Year ended December 31*<br>*(millions of dollars, except as otherwise noted)* | 2016 | 2015 | Change |
|---|---|---|---|
| Transmission | **1,584** | 1,536 | 3.1% |
| Distribution | **4,915** | 4,949 | (0.7%) |
| Other | **53** | 53 | – |
| | **6,552** | 6,538 | 0.2% |
| Transmission volumes: Average monthly Ontario 60-minute peak demand *(MW)* | **20,690** | 20,344 | 1.7% |
| Distribution volumes: Electricity distributed to Hydro One customers *(GWh)* | **26,289** | 28,764 | (8.6%) |

### Transmission Revenues

Transmission revenues increased by 3.1% in 2016 primarily due to the following:

- prior year revenues were affected by a regulatory driven reduction of $28 million related to differences between actual and forecast province-wide conservation and demand management savings during 2014, which did not recur in 2016;
- higher average monthly Ontario 60-minute peak demand mainly due to warmer weather in the second and third quarters of 2016, as well as the impact of several extremely cold days that more than offset the overall milder weather in the fourth quarter of 2016; and
- increased OEB-approved transmission rates for 2016.

### Distribution Revenues

Distribution revenues decreased by 0.7% in 2016 primarily due to the following:

- the divestiture of Hydro One Brampton in August 2015, which also caused the majority of the decrease in distribution volumes; and
- lower overall energy consumption resulting from milder weather in the first and fourth quarters of 2016; partially offset by
- higher power costs from generators that are passed on to customers, excluding the impact of divestiture of Hydro One Brampton;
- increased OEB-approved distribution rates for 2016; and
- increased revenues due to a rate order related to shared-use revenue.

## Operation, Maintenance and Administration Costs

| *Year ended December 31*<br>*(millions of dollars)* | 2016 | 2015 | Change |
|---|---|---|---|
| Transmission | **382** | 414 | (7.7%) |
| Distribution | **608** | 633 | (3.9%) |
| Other | **79** | 88 | (10.2%) |
| | **1,069** | 1,135 | (5.8%) |

## Transmission OM&A Costs

Transmission OM&A decreased by 7.7% in 2016 primarily due to lower project cost and inventory write-downs coupled with lower activity related to transformer equipment refurbishments and stations maintenance.

## Distribution OM&A Costs

Distribution OM&A decreased by 3.9% in 2016 primarily due to the following:

- decrease in bad debt expense including the impact of revised estimates of uncollectible accounts;
- the divestiture of Hydro One Brampton in August 2015;
- lower support services costs; and
- lower costs associated with underground distribution cable locates; partially offset by
- higher volume of vegetation management activities.

## Other OM&A Costs

Other OM&A decreased by 10.2% in 2016 primarily due to lower costs relating to the integration of acquired local distribution companies and lower consulting costs.

## Depreciation and Amortization

The increase of $19 million or 2.5% in depreciation and amortization costs for 2016 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.

## Financing Charges

The increase of $17 million or 4.5% in financing charges for 2016 was mainly due to the following:

- an increase in interest expense on long-term debt mainly due to the increase in weighted average long-term debt balance outstanding during the year, partially offset by a decrease in the weighted average interest rate for long-term debt; and
- an increase in interest expense on short-term notes mainly due to the increase in weighted average short-term notes balance outstanding during the year, as well as an increase in the weighted average interest rate for short-term notes.

## Income Tax Expense

Income tax expense in 2016 increased by $34 million compared to 2015, and the Company realized an effective tax rate of approximately 15.7% in 2016, compared to approximately 12.8% realized in 2015. The increase in the tax expense is primarily due to the effect of an IPO-related positive tax adjustment of $19 million in 2015, coupled with higher income before taxes in 2016.

# Common Share Dividends

In 2016, the Company declared and paid cash dividends to common shareholders as follows:

| Date Declared | Record Date | Payment Date | Amount per Share | Total Amount *(millions of dollars)* |
|---|---|---|---|---|
| February 11, 2016 | March 17, 2016 | March 31, 2016 | $0.34[1] | 202 |
| May 5, 2016 | June 14, 2016 | June 30, 2016 | $0.21 | 125 |
| August 11, 2016 | September 14, 2016 | September 30, 2016 | $0.21 | 125 |
| November 10, 2016 | December 14, 2016 | December 30, 2016 | $0.21 | 125 |
| | | | | *577* |

[1] This was the first common share dividend declared by the Company following the completion of its initial public offering in November 2015. The $0.34 per share dividend included $0.13 for the post-IPO period from November 5 to December 31, 2015, and $0.21 for the quarter ended March 31, 2016.

Following the conclusion of the fourth quarter of 2016, the Company declared a cash dividend to common shareholders as follows:

| Date Declared | Record Date | Payment Date | Amount per Share | Total Amount *(millions of dollars)* |
|---|---|---|---|---|
| February 9, 2017 | March 14, 2016 | March 31, 2017 | $0.21 | 125 |

## Divestiture of Hydro One Brampton

On August 31, 2015, a dividend was paid to the Province of Ontario (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 were included in consolidated results of Hydro One for the year ended December 31, 2015.

| *Quarter ended (millions of 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 |



## Selected Annual Financial Statistics

| *Year ended December 31 (millions of dollars, except per share amounts)* | **2016** | 2015 | 2014 |
|---|---|---|---|
| Total revenue | **6,552** | 6,538 | 6,548 |
| Net income attributable to common shareholders | **721** | 690 | 731 |
| Basic and diluted EPS | **$ 1.21** | $ 1.39 | $ 1.53 |
| Basic and diluted Adjusted EPS | **$ 1.21** | $ 1.16 | $ 1.23 |
| Dividends per common share declared | **$ 0.97**[1] | $ 1.83 | $ 0.56 |
| Dividends per preferred share declared | **$ 1.12** | $ 1.03 | $ 1.38 |

[1] The $0.97 per share dividends declared in 2016 included $0.13 for the post-IPO period from November 5 to December 31, 2015, and $0.84 for the year ended December 31, 2016.

| *December 31 (millions of dollars)* | **2016** | 2015 | 2014 |
|---|---|---|---|
| Total assets | **25,351** | 24,294 | 22,550 |
| Total non-current financial liabilities | **10,078** | 8,207 | 8,373 |

## Quarterly Results of Operations

| *Quarter ended (millions of dollars, except EPS)* | **Dec. 31, 2016** | **Sep. 30, 2016** | **Jun. 30, 2016** | **Mar. 31, 2016** | Dec. 31, 2015 | Sep. 30, 2015 | Jun. 30, 2015 | Mar. 31, 2015 |
|---|---|---|---|---|---|---|---|---|
| Revenues | **1,614** | **1,706** | **1,546** | **1,686** | 1,522 | 1,645 | 1,563 | 1,808 |
| Purchased power | **858** | **870** | **803** | **896** | 786 | 856 | 838 | 970 |
| Revenues, net of purchased power | **756** | **836** | **743** | **790** | 736 | 789 | 725 | 838 |
| Net income to common shareholders | **128** | **233** | **152** | **208** | 143 | 188 | 131 | 228 |
| Basic EPS | **$ 0.22** | **$ 0.39** | **$ 0.26** | **$ 0.35** | $ 0.26 | $ 0.39 | $ 0.27 | $ 0.47 |
| Diluted EPS | **$ 0.21** | **$ 0.39** | **$ 0.25** | **$ 0.35** | $ 0.26 | $ 0.39 | $ 0.27 | $ 0.47 |
| Basic Adjusted EPS | **$ 0.22** | **$ 0.39** | **$ 0.26** | **$ 0.35** | $ 0.24 | $ 0.32 | $ 0.22 | $ 0.38 |
| Diluted Adjusted EPS | **$ 0.21** | **$ 0.39** | **$ 0.25** | **$ 0.35** | $ 0.24 | $ 0.32 | $ 0.22 | $ 0.38 |

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

## 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.

The following table presents Hydro One's 2016 and 2015 capital investments:

| *Year ended December 31*<br>*(millions of dollars)* | 2016 | 2015 | Change |
|---|---|---|---|
| Transmission | | | |
| Sustaining | **750** | 706 | 6.2% |
| Development | **156** | 166 | (6.0%) |
| Other | **82** | 71 | 15.5% |
| | **988** | 943 | 4.8% |
| Distribution | | | |
| Sustaining | **384** | 398 | (3.5%) |
| Development | **217** | 220 | (1.4%) |
| Other | **102** | 93 | 9.7% |
| | **703** | 711 | (1.1%) |
| Other | **6** | 9 | (33.3%) |
| Total capital investments | **1,697** | 1,663 | 2.0% |

### Transmission Capital Investments

Transmission capital investments increased by $45 million or 4.8% in 2016. Principal impacts on the levels of capital investments included:

- an increased volume of work on overhead line refurbishments and insulator replacements;
- an increased volume of integrated station component replacements to sustain certain aging assets at transmission stations;
- continued work on major local area supply network development projects, such as the Holland Transmission Station, the Hawthorne Transmission Station, and the Toronto Midtown Transmission Reinforcement; and
- increased investments relating to information technology infrastructure and customer programs, enhancement projects, including investments to integrate mobile technology with the Company's existing work management tools; partially offset by
- decreased investments in system enhancement projects, primarily due to completion of certain projects and a difference in timing of work on other projects; and
- completion of the Guelph Area Transmission Refurbishment project.

### Distribution Capital Investments

Distribution capital investments decreased by $8 million or 1.1% in 2016. Principal impacts on the levels of capital investments included:

- reduced capital expenditures due to the divestiture of Hydro One Brampton in 2015; and
- a lower volume of work within station refurbishment programs and lower volume of spare transformer purchases; partially offset by
- increased investments related to information technology infrastructure and customer programs together with upgrade and enhancement projects, including investments to integrate mobile technology with the Company's existing work management tools; and
- investments in smart grid technology to mitigate power quality impacts of distributed generation and to improve outage response times.

## Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2016:

| Project Name | Location | Type | Anticipated In-Service Date | Estimated Cost | Capital Cost To-Date |
|---|---|---|---|---|---|
| **Development Projects:** | | | | | |
| Guelph Area Transmission Refurbishment | Guelph area Southwestern Ontario | Transmission line upgrade | September 2016[1] | $87 million | $86 million |
| Toronto Midtown Transmission Reinforcement | Toronto Southwestern Ontario | New transmission line | December 2016[2] | $118 million | $113 million |
| Supply to Essex County Transmission Reinforcement | Windsor-Essex area Southwestern Ontario | New transmission line and station | 2018 | $73 million | $13 million |
| Clarington Transmission Station | Oshawa area Southwestern Ontario | New transmission station | 2018 | $267 million | $192 million |
| Northwest Bulk Transmission Line | Thunder Bay Northwestern Ontario | New transmission line | To be determined | To be determined | – |
| East-West Tie Station Expansion | Northern Ontario | Station expansion | 2020 | $166 million | – |
| **Sustainment Projects:** | | | | | |
| Bruce A Transmission Station | Tiverton Southwestern Ontario | Station sustainment | 2019 | $109 million | $83 million |
| Richview Transmission Station Circuit Breaker Replacement | Toronto Southwestern Ontario | Station sustainment | 2019 | $102 million | $68 million |
| Lennox Transmission Station Circuit Breaker Replacement | Napanee Southeastern Ontario | Station sustainment | 2020 | $95 million | $15 million |
| Beck #2 Transmission Station Circuit Breaker Replacement | Niagara area Southwestern Ontario | Station sustainment | 2021 | $93 million | $28 million |

[1] Major portions of the project were completed and placed in-service in September 2016. Work on certain minor portions of the project continues in the first quarter of 2017.

[2] Major portions of the project were completed and placed in-service in December 2016. Work on certain minor portions of the project continues in the first quarter of 2017.

## Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the next five years. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. These estimates differ from the prior year disclosures, reflecting annual increases of $126 million for 2017, $113 million for 2018, $239 million for 2019, and $360 million for 2020. These future capital investments reflect management's best estimates and, as applicable, projections included in rate filings currently in process. These projections and the timing of expenditures are in large part subject to approval by the OEB, and will be adjusted going forward as appropriate to reflect rate decisions by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2017 to 2021, by business segment:

| *(millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Transmission | 1,086 | 1,132 | 1,217 | 1,278 | 1,486 |
| Distribution | 648 | 647 | 771 | 735 | 749 |
| Other | 12 | 9 | 8 | 6 | 8 |
| **Total capital investments** | **1,746** | **1,788** | **1,996** | **2,019** | **2,243** |

The following table summarizes Hydro One's annual projected capital investments for 2017 to 2021, by category:

| *(millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Sustaining | 1,107 | 1,165 | 1,219 | 1,327 | 1,546 |
| Development | 414 | 400 | 484 | 487 | 490 |
| Other[1] | 225 | 223 | 293 | 205 | 207 |
| **Total capital investments** | **1,746** | **1,788** | **1,996** | **2,019** | **2,243** |

[1] "Other" capital expenditures consist of special projects, such as those relating to information technology.

## Summary Of Sources And Uses Of Cash

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

| *Year ended December 31*<br>*(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Cash provided by (used in) operating activities | **1,656** | (1,248) |
| Cash provided by financing activities | **161** | 2,954 |
| Cash used in investing activities | **(1,861)** | (1,712) |
| **Decrease in cash and cash equivalents** | **(44)** | (6) |

### Primary factors behind the increase in cash provided by operating activities

The increase in cash provided by operating activities is primarily due to a deferred tax recovery of $2.8 billion recorded in 2015 that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime.

### Primary factors behind the decrease in cash provided by financing activities

Sources of cash

- The Company received $2.3 billion proceeds from issuance of long-term debt in 2016, compared to $350 million received last year.
- The Company received $3,031 million proceeds from issuance of short-term notes in 2016, compared to $2,891 million received last year.
- In 2015, the Company received $2.6 billion proceeds from common shares issued to the Province prior to the completion of the initial public offering (IPO).

Uses of cash

- Dividends paid in 2016 were $596 million, consisting of $577 million common share dividends and $19 million preferred share dividends, compared to $888 million paid in 2015. 2015 dividends consisted of $75 million common share dividends, $13 million preferred share dividends, as well as an $800 million special dividend paid to the Province prior to the completion of the IPO.
- The Company repaid $4,053 million of short-term notes, compared to $1,400 million repaid last year.
- The Company repaid $502 million of long-term debt in 2016 compared to $585 million repaid last year.

### Primary factors behind the increase in cash used in investing activities

Uses of cash

- Capital expenditures were $29 million higher in 2016, primarily due to increased transmission capital investments consistent with the Company's ongoing capital investment program.
- In 2016, the Company paid $226 million to acquire Great Lakes Power, compared to a total of $90 million paid in 2015 to acquire Haldimand County Utilities Inc. (Haldimand Hydro) and Woodstock Hydro Holdings Inc. (Woodstock Hydro).
- In August 2015, an investment of $53 million was made in Hydro One Brampton prior to its divestiture to the Province.



## 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 bank 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 up to 365 days. At December 31, 2016, Hydro One Inc. had $469 million in commercial paper borrowings outstanding, compared to $1,491 million outstanding at December 31, 2015. In addition, the Company and Hydro One Inc. have revolving bank credit facilities totalling $2,550 million maturing in 2021. 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, 2016, the Company's long-term debt in the principal amount of $10,671 million included $10,523 million long-term debt issued under Hydro One Inc.'s Medium Term Note (MTN) Program and long-term debt in the principal amount of $148 million held by Great Lakes Power. At December 31, 2016, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2017 and 2064, and at December 31, 2016, had an average term to maturity of approximately 15.9 years and a weighted average coupon of 4.3%.

On March 30, 2016, Hydro One filed a final universal short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, up to $8.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on April 30, 2018. Hydro One filed the Universal Base Shelf Prospectus in part to facilitate the secondary offerings of outstanding shares of the Company by the Province, and to provide the Company with increased financing flexibility going forward. In 2016, Hydro One completed a secondary offering of a portion of its common shares previously owned by the Province. See section "Other Developments – Change in Hydro One Ownership Structure" for details of this transaction. Upon closing of the transaction, $6,030 million remained available under the Universal Base Shelf Prospectus.

At December 31, 2016, the Company and Hydro One Inc. were in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

### Credit Ratings

At December 31, 2016, Hydro One's corporate credit ratings were as follows:

| Rating Agency | Corporate Credit Rating |
|---|---|
| Standard & Poor's Rating Services (S&P) | A |

Hydro One has not obtained a credit rating in respect of any of its securities. An issuer rating from S&P is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due but it does not apply to any specific financial obligation. An obligor with a long-term credit rating of 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

The rating above is not a recommendation to purchase, sell or hold any of Hydro One's securities and does not comment on the market price or suitability of any of the securities for a particular investor. There can be no assurance that the rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn entirely by S&P at any time in the future. Hydro One has made, and anticipates making, payments to S&P pursuant to agreements entered into with S&P in respect of the rating assigned to Hydro One and expects to make payments to S&P in the future to the extent it obtains a rating specific to any of its securities.

At December 31, 2016, Hydro One Inc.'s long-term and short-term debt ratings were as follows:

| Rating Agency | Short-term Debt Rating | Long-term Debt Rating |
|---|---|---|
| DBRS Limited | R-1 (low) | A (high) |
| Moody's Investors Service | Prime-2 | A3 |
| S&P | A-1 | A |

### Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated return on equity (ROE) is derived using a formulaic approach that takes into account changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. 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 2016, Hydro One contributed approximately $108 million to its pension plan, compared to contributions of approximately $177 million in 2015, and incurred $116 million in net periodic pension benefit costs, compared to $163 million incurred in 2015.

In June 2016, Hydro One Inc. filed an actuarial valuation of its Pension Plan as at December 31, 2015. Based on this valuation and 2016 levels of pensionable earnings, the 2016 annual employer contributions have decreased by approximately $72 million from $180 million as estimated at December 31, 2015, primarily due to improvements in the funded status of the plan and future actuarial assumptions. The decrease also reflects the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. The updated actuarial valuation resulted in a $25 million decrease in 2016 revenue with a corresponding decrease in OM&A costs, as the lower pension contributions will be returned to customers through the pension cost variance deferral account in future rate applications. The Company estimates that total pension contributions for 2017 and 2018 will be approximately $105 million and $102 million, respectively.

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".

## 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 and commercial commitments:

| *December 31, 2016* *(millions of 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 | 10,671 | 602 | 1,484 | 1,156 | 7,429 |
| Long-term debt – interest payments | 8,145 | 456 | 827 | 754 | 6,108 |
| Short-term notes payable | 469 | 469 | – | – | – |
| Pension contributions[1] | 207 | 105 | 102 | – | – |
| Environmental and asset retirement obligations | 243 | 27 | 51 | 65 | 100 |
| Outsourcing agreements | 374 | 165 | 196 | 4 | 9 |
| Operating lease commitments | 42 | 11 | 16 | 13 | 2 |
| Long-term software/meter agreement | 73 | 17 | 33 | 18 | 5 |
| Total contractual obligations | 20,224 | 1,852 | 2,709 | 2,010 | 13,653 |
| Other commercial commitments *(by year of expiry)* | | | | | |
| Credit facilities[2] | 2,550 | – | – | 2,550 | – |
| Letters of credit[3] | 174 | 174 | – | – | – |
| Guarantees[4] | 330 | 330 | – | – | – |
| Total other commercial commitments | 3,054 | 504 | – | 2,550 | – |

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2017 and 2018 minimum pension contributions are based on an actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings.

[2] On August 15, 2016, Hydro One Inc. terminated its credit facilities totalling $2.3 billion maturing in June 2020 and October 2018, and entered into a new $2.3 billion credit facility maturing in June 2021. On November 7, 2016, the maturity date of Hydro One's $250 million credit facility was extended from November 2020 to November 2021.

[3] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, and letters of credit totalling $24 million provided as prudential support.

[4] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

## 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 time frames.

The following table summarizes the status of 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 | 2017-2018 | Transmission – Cost-of-service | OEB decision pending |
| Hydro One Networks | 2015-2017 | Distribution – Custom | OEB decision received |
| B2M LP | 2015-2019 | Transmission – Cost-of-service | OEB decision received |
| Great Lakes Power | 2017 | Transmission – Cost-of-service | OEB decision pending |
| Mergers Acquisitions Amalgamations and Divestitures | | | |
| Great Lakes Power | n/a | Acquisition | OEB decision received |
| Orillia Power | n/a | Acquisition | OEB decision pending |
| Leave to Construct | | | |
| Supply to Essex County Transmission Reinforcement Project | n/a | Section 92 | OEB decision received |

Hydro One has obtained revenue requirement approvals from the OEB, subject to certain annual adjustments, 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 key elements and status of Hydro One's electricity rate applications:

| Application | Year | ROE Allowed (A) or Forecast (F) | Rate Base | Rate Application Status | Rate Order Status |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| Hydro One Networks | 2016 | 9.19% (A) | $10,040 million | Approved in January 2015 | Approved in January 2016 |
| | 2017 | 8.78% (A) | $10,554 million | Filed in May 2016 | To be filed in 2017 Q1 |
| | 2018 | 8.78% (F) | $11,226 million | Filed in May 2016 | To be filed in 2017 Q4 |
| B2M LP | 2016 | 9.19% (A) | $516 million | Approved in December 2015 | Approved in January 2016 |
| | 2017 | 8.78% (A) | $509 million | Approved in December 2015 | Filed in December 2016 |
| | 2018 | 8.78% (F) | $502 million | Approved in December 2015 | To be filed in 2017 Q4 |
| | 2019 | 8.78% (F) | $496 million | Approved in December 2015 | To be filed in 2018 Q4 |
| Great Lakes Power | 2017 | 9.19% (F) | $218 million | Filed in December 2016 | Filed in December 2016 |
| **Distribution** | | | | | |
| Hydro One Networks | 2016 | 9.19% (A) | $6,863 million | Approved in March 2015 | Approved in April 2015 |
| | 2017 | 8.78% (A) | $7,190 million | Approved in March 2015 | Approved in December 2016 |

### Hydro One Networks

On May 31, 2016, Hydro One Networks filed a cost-of-service application with the OEB for 2017 and 2018 transmission rates. The application seeks approval of rate base of $10,554 million for 2017 and $11,226 million for 2018. In October 2016, the OEB issued updated cost of capital parameters for rates effective in 2017, including an updated 2017 allowed ROE of 8.78%. The application also lays out a planned transmission capital investment program for the five-year period ending on December 31, 2021, with investments in capital spending primarily to address reliability, safety and customer needs, in a cost-effective manner. Management expects that a decision will be received in the first half of 2017, and that new rates will be retroactive to January 1, 2017. Future transmission rate applications are anticipated to be filed under the OEB's incentive-based regulatory framework.

Hydro One Networks plans to submit an application for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework in the first quarter of 2017.

### B2M LP

On January 14, 2016, the OEB issued its Decision and Rate Order approving the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates. On December 1, 2016, B2M LP filed a Draft Rate Order with a revised 2017 revenue requirement of $34 million, reflecting updated 2017 cost of capital parameters issued by the OEB in October 2016.

### Other Regulatory Developments

#### OEB Pension and Other Post-Employment Benefits (OPEB) Generic Hearing

In 2015, the OEB began a consultation process to examine pensions and OPEBs in rate-regulated utilities, with the objectives of developing standard principles to guide its review of pension and OPEB related costs in the future, and to establish specific requirements for applications and appropriate and consistent regulatory mechanisms for cost recovery. Hydro One and other stakeholders filed written submissions with respect to initial OEB questions intended to solicit views on the key issues of interest to the OEB. Following a stakeholder forum in July 2016, updated written submissions were filed with the OEB in September 2016. It is anticipated that subsequent to the OEB's review of the updated written submissions, the OEB will outline principles to guide its review of pension and OPEB related costs in the future, and provide further guidance on application requirements and regulatory mechanisms for cost recovery.

## Other Developments

### Change in Hydro One Ownership Structure

In November 2015, Hydro One and the Province completed an IPO on the Toronto Stock Exchange of approximately 89.3 million common shares of Hydro One, representing 15% of the Province's ownership position. Prior to the completion of the IPO, Hydro One and its subsidiary, Hydro One Inc., completed a series of transactions (Pre-IPO 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. In April 2016, the Province completed a secondary offering of 83.3 million common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from either of the sales of common shares by the Province. At December 31, 2016, the Province directly holds approximately 70.1% of Hydro One's total issued and outstanding common shares.

### Class Action Lawsuit

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities Inc., and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. A certification motion in the class action is pending. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

### Acquisitions

#### Integration of Haldimand Hydro and Woodstock Hydro

In 2015, the Company acquired Haldimand Hydro and Woodstock Hydro, two Ontario-based local distribution companies. In September 2016, the Company successfully completed the integration of both entities, including the integration of employees, customer and billing information, business processes, and operations.

#### Acquisition of Great Lakes Power

On October 31, 2016, following receipt of regulatory approval of the transaction by the OEB, Hydro One completed the acquisition of Great Lakes Power, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario. The total purchase price for Great Lakes Power was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. On January 16, 2017, Great Lakes Power's name was changed to Hydro One Sault Ste. Marie LP.

On December 23, 2016, Great Lakes Power filed an application for 2017 rates, requesting an increase to the approved 2016 revenue requirement of 1.9%, resulting in an updated revenue requirement of $41 million.

#### Acquisition of Orillia Power

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

## Hydro One Work Force

Hydro One has a skilled and flexible work force of approximately 5,500 regular employees and over 2,000 non-regular employees province-wide, comprising a mix of skilled trades, 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 flexibly utilize 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, 2016.

| | Regular Employees | Non-Regular Employees | Total |
|---|---|---|---|
| Power Workers' Union (PWU) | 3,470 | 698[1] | 4,168 |
| The Society of Energy Professionals (Society) | 1,365 | 44 | 1,409 |
| Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2] | – | 1,275 | 1,275 |
| Total employees represented by unions | 4,835 | 2,017 | 6,852 |
| Management and non-represented employees | 659 | 28 | 687 |
| Total employees | 5,494 | 2,045 | 7,539 |

1 Includes 528 non-regular "hiring hall" employees covered by the 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).

### Share-based Compensation

During 2016, the Company granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled. At December 31, 2016, 230,600 PSUs and 254,150 RSUs were outstanding. No long-term incentive awards were granted during 2015.

## Non-Gaap Measures

### Funds from Operations (FFO) and Adjusted FFO

FFO is defined as net cash from operating activities, adjusted for (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 consistent measures 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*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Net cash from (used in) operating activities | 1,656 | (1,248) |
| Changes in non-cash balances related to operations | (134) | (213) |
| Preferred share dividends | (19) | (13) |
| Distributions to noncontrolling interest | (9) | (5) |
| FFO | 1,494 | (1,479) |
| Less: Deferred income tax asset[1] | – | (2,810) |
| Adjusted FFO | 1,494 | 1,331 |

[1] Impact of deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime.

### Adjusted EPS

The following basic and diluted Adjusted 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, 2016 and 2015. The supplementary pro forma disclosure is used internally by management subsequent to the IPO of the Company's common shares in November 2015 to assess the Company's performance and is considered useful because it eliminates the impact of a different and non-comparable number of shares outstanding and held by the Province prior to the IPO. Adjusted EPS is considered an important measure and management believes that presenting it consistently for all periods based on the number of outstanding shares on, and subsequent to, the IPO provides users with a comparative basis to evaluate the operations of the Company.

| *Year ended December 31* | 2016 | 2015 |
|---|---|---|
| Net income attributable to common shareholders *(millions of dollars)* | 721 | 690 |
| Pro forma weighted average number of common shares | | |
| Basic | 595,000,000 | 595,000,000 |
| Effect of dilutive stock-based compensation plans | 1,700,823 | 94,691 |
| Diluted | 596,700,823 | 595,094,691 |
| Adjusted EPS | | |
| Basic | $ 1.21 | $ 1.16 |
| Diluted | $ 1.21 | $ 1.16 |

## 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*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Net cash from (used in) operating activities | 1,656 | (1,248) |
| Less: Deferred income tax asset[1] | – | (2,810) |
| Adjusted net cash from operating activities | 1,656 | 1,562 |

[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, adjusted 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.

## Related Party Transactions

The Province is the majority shareholder of Hydro One. The IESO, Ontario Power Generation Inc. (OPG), OEFC, 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, 2016:

| | | Year ended December 31 | |
|---|---|---|---|
| | | 2016 | 2015 |
| Related Party | Transaction | *(millions of dollars)* | |
| Province[1] | Dividends paid | 451 | 888 |
| | Common shares issued[2] | – | 2,600 |
| | IPO costs subsequently reimbursed by the Province[3] | – | 7 |
| IESO | Power purchased | 2,096 | 2,318 |
| | Revenues for transmission services | 1,549 | 1,548 |
| | Distribution revenues related to rural rate protection | 125 | 127 |
| | Distribution revenues related to the supply of electricity to remote northern communities | 32 | 32 |
| | Funding received related to Conservation and Demand Management programs | 63 | 70 |
| OPG | Power purchased | 6 | 11 |
| | Revenues related to provision of construction and equipment maintenance services | 5 | 7 |
| | Costs expensed related to the purchase of services | 1 | 1 |
| OEFC | Payments in lieu of corporate income taxes[4] | – | 2,933 |
| | Power purchased from power contracts administered by the OEFC | 1 | 6 |
| | Indemnification fee paid (terminated effective October 31, 2015) | – | 8 |
| OEB | OEB fees | 11 | 12 |
| Hydro One Brampton[1] | Revenues from management, administrative and smart meter network services | 3 | 1 |

[1] On August 31, 2015, Hydro One Inc. completed the spin-off of its subsidiary, Hydro One Brampton, to the Province.
[2] On November 4, 2015, Hydro One issued common shares to the Province for proceeds of $2.6 billion.
[3] In 2015, Hydro One incurred certain IPO related expenses totalling $7 million, which were subsequently reimbursed to the Company by the Province.
[4] In 2015, Hydro One made PILs to the OEFC totalling $2.9 billion, including departure tax of $2.6 billion.

At December 31, 2016, the amounts due from and due to related parties as a result of the transactions described above were $158 million and $147 million, compared to $191 million and $138 million at December 31, 2015, respectively. At December 31, 2016, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $143 million, compared to $134 million at December 31, 2015.

# 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 outstanding or 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, costs of debt and income taxes, or to earn a particular ROE. 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 ROE 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, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to obtain acceptable rate decisions or to 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 Conservation and Demand Management programs whose results exceed forecasted expectations.

#### *Risks Relating to Rate-Setting Models for Transmission and Distribution*

The OEB approves and periodically changes the ROE for transmission and distribution businesses. The OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

The OEB's recent Custom Incentive Rate-setting model requires that the term of a custom rate application be a minimum five-year period. There are risks associated with forecasting key inputs such as revenues, operating expenses and capital, 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.

After rates are set as part of a part of a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital (including ROE), working capital allowance or sales volumes. If there were an increase in interest rates over the period of a rate decision and no corresponding changes were permitted to the

Company's allowed cost of capital (including ROE), then the result could be a decrease in the Company's financial performance.

To the extent that the OEB approves an In-Service Variance Account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

### *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 may be 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.

Any future regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures 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 in connection with the IPO of the Company, 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 at least the next five years due to the reduction of cash income taxes payable by Hydro One associated primarily with a higher capital cost allowance. There is a risk that, in current or 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); Reserve) lands, and lands over which First Nations and Métis have Aboriginal, treaty, or other legal claims. 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 and/or settlement of 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 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 citizens. 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 and restore the lands 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 example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, 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 North American Electric Reliability Corporation (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, requirements 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. 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. Where insurance is available for other assets, such insurance coverage may have deductibles, limits and/or exclusions. 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.

## 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. The Company must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information and information regarding consumers, wholesalers, generators and retailers.

Cyber-attacks or unauthorized access to corporate and information technology systems 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. Due to operating critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the normal course of its operations, the Company collects, uses, processes and stores information, which could be exposed in the event of a cyber-security incident or other unauthorized access, such as information about customers, suppliers, counterparties and employees.

Security and system disaster recovery controls are in place; however, 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.

## Work Force Demographic Risk

By the end of 2016, approximately 22% of the Company's employees who are members of the Company's defined benefit pension plan were eligible for retirement under that plan, and by the end of 2017, up to approximately 23% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During each of 2016 and 2015, approximately 3% of the Company's work force elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue 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 PWU or the Society. 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 reached an agreement with the PWU 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 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 EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also 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 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 debt principal repayments, including $602 million in 2017, $753 million in 2018, and $731 million in 2019. 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 mature within approximately one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2017 and 2018. 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, an inability of the Corporation to comply with its debt covenants, 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 ROE 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 ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2018 net income by approximately $23 million and its distribution business' 2018 net income by approximately $15 million. 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 agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. 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 numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. 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. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks 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

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company.

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. 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.

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "SF6". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

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 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, 2015, and was filed in June 2016, covering a three year period from 2016 to 2018. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2018 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that 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 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 a third party 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 and fully transitioned, 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 becomes involved in, is named as a party to and is 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. See also "Other Developments – Class Action Lawsuit".

### Transmission Assets on Third-Party Lands Risk

Some of the lands on which the Company's transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned lands or has occupational rights that are subject to expiry, it may incur material costs to obtain or renew such occupational rights, or if such occupational rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupational rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations.

### Reputational and Public Opinion Risk

Reputation risk is the risk of a negative impact to the Company's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. The Company's reputation could be negatively impacted by changes in public opinion, attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events could have negative impacts on the Company's business and prospects including, but not limited to, delays or denials of requisite approvals and accommodations for the Company's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

## Risks Relating to the Company's Relationship with the Province

### Ownership and Continued Influence by the Province and Voting Power; Share Ownership Restrictions

The Province currently owns approximately 70.1% of the outstanding 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). 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 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.

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.

### 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 and Judgments

The preparation of Hydro One Consolidated Financial Statements requires the Company to make key estimates and critical 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 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. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. 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

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, 2016 decreased to 3.90% (from 4.00% at December 31, 2015) for pension benefits and decreased to 3.90% (from 4.10% used at December 31, 2015) for the post-retirement and post-employment plans. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for the pension, 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. The Company believes 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 increased from 1.50% per annum as at December 31, 2015 to approximately 1.80% per annum as at December 31, 2016. 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, 2016.

## 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 used at December 31, 2016 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B (compared to 100% of 2014 Canadian Pensioners Mortality Public Sector table projected generationally using improvement Scale B used at December 31, 2015). The mortality table was updated based on a review of the historical mortality experience of the pension plan members.

## 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 $23 million increase in 2016 interest cost plus service cost, and a $289 million increase in the benefit liability at December 31, 2016.

### Business Combinations

Management's judgment is required to estimate the purchase price, to identify and to determine fair value of all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions.

### Taxes

Hydro One assesses the likelihood that deferred tax assets will be recovered from future taxable income. To the extent management considers it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is recognized.

### 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. The Company regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2016, 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, 2016. Goodwill represents the cost of acquired distribution and transmission 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, 2016, 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, 2016.

# New Accounting Pronouncements

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One.

## Recently Adopted Accounting Guidance

| ASU | Date issued | Description | Effective date | Impact on Hydro One |
|---|---|---|---|---|
| 2014-16 | November 2014 | This update clarifies that all relevant terms and features should be considered in evaluating the nature of a host contract for hybrid financial instruments issued in the form of a share. The nature of the host contract depends upon the economic characteristics and risks of the entire hybrid financial instrument. | January 1, 2016 | No material impact upon adoption |
| 2015-01 | January 2015 | Extraordinary items are no longer required to be presented separately in the income statement. | January 1, 2016 | No material impact upon adoption |
| 2015-02 | February 2015 | Guidance on analysis to be performed to determine whether certain types of legal entities should be consolidated. | January 1, 2016 | No material impact upon adoption |
| 2015-03 | April 2015 | Debt issuance costs are required to be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums. | January 1, 2016 | Reclassification of deferred debt issuance costs and net unamortized debt premiums as an offset to long-term debt. Applied retrospectively. |
| 2015-05 | April 2015 | Cloud computing arrangements that have been assessed to contain a software licence should be accounted for as internal-use software. | January 1, 2016 | No material impact upon adoption |
| 2015-16 | September 2015 | Adjustments to provisional amounts that are identified during the measurement period of a business combination in the reporting period in which the adjustment amount is determined are required to be recognized. The amount recorded in current period earnings are required to be presented separately on the face of the income statement or disclosed in the notes by line item. | January 1, 2016 | No material impact upon adoption |
| 2015-17 | November 2015 | All deferred tax assets and liabilities are required to be classified as noncurrent on the balance sheet. | January 1, 2017 | This ASU was early adopted as of April 1, 2016 and was applied prospectively. As a result, the current portions of the Company's deferred income tax assets are reclassified as noncurrent assets on the consolidated Balance Sheet. Prior periods were not retrospectively adjusted. |
| 2016-09 | March 2016 | Several aspects of the accounting for share-based payment transactions were simplified, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. | January 1, 2017 | This ASU was early adopted as of October 1, 2016 and was applied retrospectively. As a result, the Company accounts for forfeitures as they occur. There were no other material impacts upon adoption. |

## Recently Issued Accounting Guidance Not Yet Adopted

| ASU | Date issued | Description | Effective date | Anticipated impact on Hydro One |
|---|---|---|---|---|
| 2014-09<br>2015-14<br>2016-08<br>2016-10<br>2016-12<br>2016-20 | May 2014 – December 2016 | ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard. | January 1, 2018 | Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is now underway and will continue through to the third quarter of 2017, with the end result being a determination of the financial impact of this standard. The Company is on track for implementation of this standard by the effective date. |
| 2016-01 | January 2016 | This update 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. | January 1, 2018 | Under assessment |
| 2016-02 | February 2016 | Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. | January 1, 2019 | An initial assessment is currently underway encompassing a review of all existing leases, which will be followed by a detailed review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date. |
| 2016-05 | March 2016 | The amendments clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under Topic 815 does not, in and of itself, require de-designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. | January 1, 2018 | Under assessment |
| 2016-06 | March 2016 | Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts. | January 1, 2017 | No material impact |
| 2016-07 | March 2016 | The requirement to retroactively adopt the equity method of accounting if an investment qualifies for use of the equity method as a result of an increase in the level of ownership or degree of influence has been eliminated. | January 1, 2017 | No material impact |
| 2016-11 | May 2016 | This amendment covers the SEC Staff's rescinding of certain SEC Staff observer comments that are codified in Topic 605 and Topic 932, effective upon the adoption of Topic 606 and Topic 815, effective to coincide with the effective date of Update 2014-16. | January 1, 2019 | No material impact |

| ASU | Date issued | Description | Effective date | Anticipated impact on Hydro One |
|---|---|---|---|---|
| 2016-13 | June 2016 | The amendment provides users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. | January 1, 2019 | Under assessment |
| 2016-15 | August 2016 | The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice. | January 1, 2018 | Under assessment |
| 2016-16 | October 2016 | The amendment eliminates the prohibition of recognizing current and deferred income taxes for an intra-entity asset transfer, other than inventory, until the asset has been sold to an outside party. The amendment will permit income tax consequences of such transfers to be recognized when the transfer occurs. | January 1, 2018 | Under assessment |
| 2016-18 | November 2016 | The amendment requires that restricted cash or restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning and end-of-period balances in the statement of cash flows. | January 1, 2018 | Under assessment |
| 2017-01 | January 2017 | The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. | January 1, 2018 | Under assessment |

## Summary of Fourth Quarter Results of Operations

| *Three months ended December 31*<br>*(millions of dollars, except EPS)* | 2016 | 2015 | Change |
|---|---|---|---|
| Revenues | | | |
| Distribution | 1,228 | 1,148 | 7.0% |
| Transmission | 373 | 361 | 3.3% |
| Other | 13 | 13 | – |
| | 1,614 | 1,522 | 6.0% |
| Costs | | | |
| Purchased power | 858 | 786 | 9.2% |
| OM&A | | | |
| Distribution | 163 | 146 | 11.6% |
| Transmission | 98 | 126 | (22.2%) |
| Other | 26 | 29 | (10.3%) |
| | 287 | 301 | (4.7%) |
| Depreciation and amortization | 204 | 193 | 5.7% |
| | 1,349 | 1,280 | 5.4% |
| Income before financing charges and income taxes | 265 | 242 | 9.5% |
| Financing charges | 101 | 94 | 7.4% |
| Income before income taxes | 164 | 148 | 10.8% |
| Income tax expense | 29 | 1 | 100.0% |
| Net income | 135 | 147 | (8.2%) |
| Net income attributable to common shareholders of Hydro One | 128 | 143 | (10.5%) |
| Basic EPS | $ 0.22 | $ 0.26 | (15.4%) |
| Diluted EPS | $ 0.21 | $ 0.26 | (19.2%) |
| Capital investments | | | |
| Distribution | 201 | 198 | 1.5% |
| Transmission | 274 | 251 | 9.2% |
| Other | 2 | 2 | – |
| | 477 | 451 | 5.8% |

### Net Income

Net income attributable to common shareholders for the quarter ended December 31, 2016 of $128 million is a decrease of $15 million or 10.5% from the prior year. Excluding the effect of an IPO-related positive tax adjustment of $19 million in the fourth quarter of 2015, net income for the quarter increased by 3.2%.

### Revenues

The quarterly increase of $12 million or 3.3% in transmission revenues was primarily due to higher average monthly Ontario 60-minute peak demand as several extremely cold days during the quarter increased peak transmission demand and OEB-approved transmission rate increases.

The quarterly increase of $80 million or 7.0% in distribution revenues was primarily due to higher power costs from generators that are passed on to customers and increased OEB-approved distribution rates for 2016, partially offset by lower energy consumption resulting from milder weather.

### OM&A Costs

The quarterly decrease of $28 million or 22.2% in transmission OM&A costs was primarily due to lower project cost and inventory write-downs and lower expenditures related to forestry control and line clearing on the Company's transmission rights-of-way.

The quarterly increase of $17 million or 11.6% in distribution OM&A costs was primarily due to higher volume of vegetation management activities, partially offset by lower costs related to restoring power services and storm response.

### Depreciation and Amortization

The increase of $11 million or 5.7% in depreciation and amortization costs for the fourth quarter of 2016 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.

### Financing Charges

The quarterly increase of $7 million or 7.4% in financing charges was primarily due to an increase in interest expense on long-term debt resulting from the increase in weighted average long-term debt outstanding during the quarter.

### Income Tax Expense

Income tax expense for the fourth quarter of 2016 increased by $28 million compared to 2015, and the Company realized an effective tax rate of approximately 17.7% in the fourth quarter of 2016 compared to approximately 0.7% in 2015. The increase in tax expense is primarily due to the following:

- the effect of an IPO-related positive tax adjustment of $19 million in the fourth quarter of 2015;
- higher income before taxes in the fourth quarter of 2016; and
- a decrease in deductible temporary differences such as capitalized pension deducted for tax purposes.

### Capital Investments

The increase in transmission capital investments during the fourth quarter was primarily due to

- an increased volume of work on insulator replacements;
- an increased volume of integrated station component replacements to replace deteriorated assets at transmission stations; and
- higher volume of demand work associated with equipment failures and spare transformer equipment purchases; partially offset by
- reduced work on the Clarington Transmission Station as the project nears completion.

The increase in distribution capital investments during the fourth quarter was primarily due to

- increased investments related to information technology infrastructure and customer programs together with upgrade and enhancement projects, including investments to integrate mobile technology with the Company's existing work management tools;
- higher volume of facility upgrades and construction of new operation centres; and
- higher volumes of work associated with further enabling certain of Hydro One's assets to be jointly used by the telecommunications and cable television industries, as well as relocation of poles, conductors and other equipment as required by municipal and provincial road authorities; partially offset by
- higher storm restoration work in the prior year primarily 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, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to: statements regarding the Company's transmission and distribution rates resulting from rate applications; 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 related to credit ratings; statements regarding ongoing and planned projects and/or initiatives, including expected results and completion dates; 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 valuations; expectations related to work force demographics; statements about collective agreements; statements related to dividends; statements related to claims; expectations regarding taxes; statements related to occupational rights; statements about non-GAAP measures; statements related to critical accounting estimates, including expectations regarding employee future benefits, environmental liabilities, and regulatory assets and liabilities; expectations related to the effect of interest rates; statements about the Company's reputation; statements regarding cyber and data security; statements related to future sales of shares of Hydro One; statements related to the Company's relationship with the Province; statements regarding recent accounting-related guidance; expectations related to tax impacts; statements related to the Universal Base Shelf Prospectus; and statements related to the Company's acquisitions, including statements about Great Lakes Power and Orillia 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 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 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 maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force 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;
- 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 functions currently outsourced if agreements 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 investments, 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, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

# 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 9, 2017.

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 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, 2016. 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<br>President and Chief<br>Executive Officer | Michael Vels<br>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, 2016 and December 31, 2015, 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, 2016 and December 31, 2015, 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 9, 2017

# Consolidated Statements of Operations and Comprehensive Income

*For the years ended December 31, 2016 and 2015*

| *Year ended December 31 (millions of Canadian dollars, except per share amounts)* | 2016 | 2015 |
|---|---|---|
| Revenues | | |
| Distribution (includes $160 related party revenues; 2015 – $159) *(Note 26)* | 4,915 | 4,949 |
| Transmission (includes $1,553 related party revenues; 2015 – $1,554) *(Note 26)* | 1,584 | 1,536 |
| Other | 53 | 53 |
| | 6,552 | 6,538 |
| Costs | | |
| Purchased power (includes $2,103 related party costs; 2015 – $2,335) *(Note 26)* | 3,427 | 3,450 |
| Operation, maintenance and administration *(Note 26)* | 1,069 | 1,135 |
| Depreciation and amortization *(Note 5)* | 778 | 759 |
| | 5,274 | 5,344 |
| Income before financing charges and income taxes | 1,278 | 1,194 |
| Financing charges *(Note 6)* | 393 | 376 |
| Income before income taxes | 885 | 818 |
| Income taxes *(Notes 7, 26)* | 139 | 105 |
| Net income | 746 | 713 |
| Other comprehensive income | – | 1 |
| Comprehensive income | 746 | 714 |
| Net income attributable to: | | |
| Noncontrolling interest *(Note 25)* | 6 | 10 |
| Preferred shareholders | 19 | 13 |
| Common shareholders | 721 | 690 |
| | 746 | 713 |
| Comprehensive income attributable to: | | |
| Noncontrolling interest *(Note 25)* | 6 | 10 |
| Preferred shareholders | 19 | 13 |
| Common shareholders | 721 | 691 |
| | 746 | 714 |
| Earnings per common share *(Note 23)* | | |
| Basic | $ 1.21 | $ 1.39 |
| Diluted | $ 1.21 | $ 1.39 |
| Dividends per common share declared *(Note 22)* | $ 0.97 | $ 1.83 |

*See accompanying notes to Consolidated Financial Statements.*

2 CONSOLIDATED FINANCIAL STATEMENTS

# Consolidated Balance Sheets

*At December 31, 2016 and 2015*

| *December 31 (millions of Canadian dollars)* | 2016 | 2015 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | 50 | 94 |
| Accounts receivable *(Note 8)* | 838 | 776 |
| Due from related parties *(Note 26)* | 158 | 191 |
| Other current assets *(Note 9)* | 102 | 105 |
| | 1,148 | 1,166 |
| Property, plant and equipment *(Note 10)* | 19,140 | 17,968 |
| Other long-term assets: | | |
| Regulatory assets *(Note 12)* | 3,145 | 3,015 |
| Deferred income tax assets *(Note 7)* | 1,235 | 1,636 |
| Intangible assets *(Note 11)* | 349 | 336 |
| Goodwill *(Note 4)* | 327 | 163 |
| Other assets | 7 | 10 |
| | 5,063 | 5,160 |
| Total assets | 25,351 | 24,294 |
| **Liabilities** | | |
| Current liabilities: | | |
| Short-term notes payable *(Note 15)* | 469 | 1,491 |
| Long-term debt payable within one year *(Note 15)* | 602 | 500 |
| Accounts payable and other current liabilities *(Note 13)* | 945 | 868 |
| Due to related parties *(Note 26)* | 147 | 138 |
| | 2,163 | 2,997 |
| Long-term liabilities: | | |
| Long-term debt (includes $548 measured at fair value; 2015 – $51) *(Notes 15, 16)* | 10,078 | 8,207 |
| Regulatory liabilities *(Note 12)* | 209 | 236 |
| Deferred income tax liabilities *(Note 7)* | 60 | 207 |
| Other long-term liabilities *(Note 14)* | 2,752 | 2,723 |
| | 13,099 | 11,373 |
| Total liabilities | 15,262 | 14,370 |
| *Contingencies and Commitments (Notes 28, 29)* | | |
| *Subsequent Events (Note 31)* | | |
| Noncontrolling interest subject to redemption *(Note 25)* | 22 | 23 |
| **Equity** | | |
| Common shares *(Notes 21, 22)* | 5,623 | 5,623 |
| Preferred shares *(Notes 21, 22)* | 418 | 418 |
| Additional paid-in capital *(Note 24)* | 34 | 10 |
| Retained earnings | 3,950 | 3,806 |
| Accumulated other comprehensive loss | (8) | (8) |
| Hydro One shareholders' equity | 10,017 | 9,849 |
| Noncontrolling interest *(Note 25)* | 50 | 52 |
| Total equity | 10,067 | 9,901 |
| | 25,351 | 24,294 |

*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, 2016 and 2015*

| *Year ended December 31, 2016 (millions of Canadian dollars)* | Common Shares | Preferred Shares | Additional Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Loss | Hydro One Shareholders' Equity | Non-controlling Interest *(Note 25)* | Total Equity |
|---|---|---|---|---|---|---|---|---|
| January 1, 2016 | 5,623 | 418 | 10 | 3,806 | (8) | 9,849 | 52 | 9,901 |
| Net income | – | – | – | 740 | – | 740 | 4 | 744 |
| Other comprehensive income | – | – | – | – | – | – | – | – |
| Distributions to noncontrolling interest | – | – | – | – | – | – | (6) | (6) |
| Dividends on preferred shares | – | – | – | (19) | – | (19) | – | (19) |
| Dividends on common shares | – | – | – | (577) | – | (577) | – | (577) |
| Stock-based compensation *(Note 24)* | – | – | 24 | – | – | 24 | – | 24 |
| December 31, 2016 | 5,623 | 418 | 34 | 3,950 | (8) | 10,017 | 50 | 10,067 |

| *Year ended December 31, 2015 (millions of Canadian dollars)* | Common Shares | Preferred Shares | Additional Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Loss | Hydro One Shareholders' Equity | Non-controlling Interest *(Note 25)* | 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 *(Note 21)* | 2,505 | 418 | – | – | – | 2,923 | – | 2,923 |
| Stock-based compensation *(Note 24)* | – | – | 10 | – | – | 10 | – | 10 |
| December 31, 2015 | 5,623 | 418 | 10 | 3,806 | (8) | 9,849 | 52 | 9,901 |

*See accompanying notes to Consolidated Financial Statements.*

# Consolidated Statements of Cash Flows

*For the years ended December 31, 2016 and 2015*

| *Year ended December 31 (millions of Canadian dollars)* | 2016 | 2015 |
|---|---|---|
| Operating activities | | |
| Net income | 746 | 713 |
| Environmental expenditures | (20) | (19) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (excluding removal costs) | 688 | 668 |
| Regulatory assets and liabilities | (16) | (3) |
| Deferred income taxes *(Note 7)* | 114 | (2,844) |
| Other | 10 | 24 |
| Changes in non-cash balances related to operations *(Note 27)* | 134 | 213 |
| Net cash from (used in) operating activities | 1,656 | (1,248) |
| Financing activities | | |
| Long-term debt issued | 2,300 | 350 |
| Long-term debt repaid | (502) | (585) |
| Short-term notes issued | 3,031 | 2,891 |
| Short-term notes repaid | (4,053) | (1,400) |
| Common shares issued | – | 2,600 |
| Dividends paid | (596) | (888) |
| Distributions paid to noncontrolling interest | (9) | (5) |
| Change in bank indebtedness | – | (2) |
| Other | (10) | (7) |
| Net cash from financing activities | 161 | 2,954 |
| Investing activities | | |
| Capital expenditures *(Note 27)* | | |
| Property, plant and equipment | (1,600) | (1,595) |
| Intangible assets | (61) | (37) |
| Capital contributions received *(Note 27)* | 21 | 57 |
| Acquisitions *(Note 4)* | (224) | (90) |
| Investment in Hydro One Brampton *(Note 4)* | – | (53) |
| Other | 3 | 6 |
| Net cash used in investing activities | (1,861) | (1,712) |
| Net change in cash and cash equivalents | (44) | (6) |
| Cash and cash equivalents, beginning of year | 94 | 100 |
| Cash and cash equivalents, end of year | 50 | 94 |

*See accompanying notes to Consolidated Financial Statements.*

# Notes to Consolidated Financial Statements

*For the years ended December 31, 2016 and 2015*

## 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. At December 31, 2016, the Province holds approximately 70.1% (2015 – 84%) of the common shares of Hydro One. See note 21 for further details regarding the reorganization of Hydro One.

The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

## 2. Significant Accounting Policies

### Basis of Consolidation and Preparation

These Consolidated Financial Statements include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

The comparative information to these Consolidated Financial Statements has been presented in a manner similar to the pooling-of-interests method. The comparative information consists 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. The comparative information has been combined using historical amounts. 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 Consolidated Financial Statements are referred to as "consolidated" for all periods presented.

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). The comparative information to these Consolidated Financial Statements includes the results 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.

### 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 Hydro One Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (previously Great Lakes Power Transmission LP (Great Lakes Power)), and 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, as well as Hydro One Remote Communities Inc. (Hydro One Remote Communities).

#### Transmission

In November 2015, the OEB approved Hydro One Networks' 2016 transmission rates revenue requirement of $1,480 million.

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. 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

In March 2015, the OEB approved Hydro One Networks' distribution revenue requirements of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The OEB has subsequently approved updated revenue requirements of $1,410 million for 2016 and $1,415 million for 2017.

On March 17, 2016, the OEB approved an increase of 2.10% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2016.

## 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 include its regulatory assets and liabilities in 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 would 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. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. 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 billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed 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 allowance for doubtful accounts is 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 and other comprehensive income 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

Prior to the IPO, 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 Financing 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 using new information about recognition or measurement as it 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 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 |
|---|---|---|---|
| Property, plant and equipment: | | | |
| Transmission | 56 years | 1% – 3% | 2% |
| Distribution | 46 years | 1% – 7% | 2% |
| Communication | 16 years | 1% –15% | 6% |
| Administration and service | 18 years | 1% –20% | 7% |
| Intangible assets | 10 years | 10% | 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.

## Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Goodwill represents the cost of acquired 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, 2016, based on the qualitative assessment performed as at September 30, 2016, 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, 2016.

## 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. 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, 2016 and 2015, 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 net of related debt 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 16 – 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. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are 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, 2016 or 2015.

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.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

### Defined Benefit Pension

Defined benefit 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.

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. 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.

## Stock-Based Compensation

### Share Grant Plans

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. Forfeitures are recognized as they occur (see note 3).

### Directors' Deferred Share Unit (DSU) Plan

The Company records the liabilities associated with its Directors' 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.

### Long-term Incentive Plan (LTIP)

The Company measures its LTIP at fair value based on the grant date share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

## 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 have been recorded 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

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One:

### Recently Adopted Accounting Guidance

| ASU | Date issued | Description | Effective date | Impact on Hydro One |
|---|---|---|---|---|
| 2014-16 | November 2014 | This update clarifies that all relevant terms and features should be considered in evaluating the nature of a host contract for hybrid financial instruments issued in the form of a share. The nature of the host contract depends upon the economic characteristics and risks of the entire hybrid financial instrument. | January 1, 2016 | No material impact upon adoption |
| 2015-01 | January 2015 | Extraordinary items are no longer required to be presented separately in the income statement. | January 1, 2016 | No material impact upon adoption |
| 2015-02 | February 2015 | Guidance on analysis to be performed to determine whether certain types of legal entities should be consolidated. | January 1, 2016 | No material impact upon adoption |
| 2015-03 | April 2015 | Debt issuance costs are required to be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums. | January 1, 2016 | Reclassification of deferred debt issuance costs and net unamortized debt premiums as an offset to long-term debt. Applied retrospectively (see note 15). |
| 2015-05 | April 2015 | Cloud computing arrangements that have been assessed to contain a software licence should be accounted for as internal-use software. | January 1, 2016 | No material impact upon adoption |
| 2015-16 | September 2015 | Adjustments to provisional amounts that are identified during the measurement period of a business combination in the reporting period in which the adjustment amount is determined are required to be recognized. The amount recorded in current period earnings are required to be presented separately on the face of the income statement or disclosed in the notes by line item. | January 1, 2016 | No material impact upon adoption |
| 2015-17 | November 2015 | All deferred tax assets and liabilities are required to be classified as noncurrent on the balance sheet. | January 1, 2017 | This ASU was early adopted as of April 1, 2016 and was applied prospectively. As a result, the current portions of the Company's deferred income tax assets are reclassified as noncurrent assets on the consolidated Balance Sheet. Prior periods were not retrospectively adjusted (see note 7). |
| 2016-09 | March 2016 | Several aspects of the accounting for share-based payment transactions were simplified, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. | January 1, 2017 | This ASU was early adopted as of October 1, 2016 and was applied retrospectively. As a result, the Company accounts for forfeitures as they occur. There were no other material impacts upon adoption. |

## Recently Issued Accounting Guidance Not Yet Adopted

| ASU | Date issued | Description | Effective date | Anticipated impact on Hydro One |
|---|---|---|---|---|
| 2014-09<br>2015-14<br>2016-08<br>2016-10<br>2016-12<br>2016-20 | May 2014 – December 2016 | ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard. | January 1, 2018 | Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is now underway and will continue through to the third quarter of 2017, with the end result being a determination of the financial impact of this standard. The Company is on track for implementation of this standard by the effective date. |
| 2016-01 | January 2016 | This update 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. | January 1, 2018 | Under assessment |
| 2016-02 | February 2016 | Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. | January 1, 2019 | An initial assessment is currently underway encompassing a review of all existing leases, which will be followed by a detailed review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date. |
| 2016-05 | March 2016 | The amendments clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under Topic 815 does not, in and of itself, require de-designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. | January 1, 2018 | Under assessment |
| 2016-06 | March 2016 | Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts. | January 1, 2017 | No material impact |
| 2016-07 | March 2016 | The requirement to retroactively adopt the equity method of accounting if an investment qualifies for use of the equity method as a result of an increase in the level of ownership or degree of influence has been eliminated. | January 1, 2017 | No material impact |
| 2016-11 | May 2016 | This amendment covers the SEC Staff's rescinding of certain SEC Staff observer comments that are codified in Topic 605 and Topic 932, effective upon the adoption of Topic 606 and Topic 815, effective to coincide with the effective date of Update 2014-16. | January 1, 2019 | No material impact |

| ASU | Date issued | Description | Effective date | Anticipated impact on Hydro One |
|---|---|---|---|---|
| 2016-13 | June 2016 | The amendment provides users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. | January 1, 2019 | Under assessment |
| 2016-15 | August 2016 | The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice. | January 1, 2018 | Under assessment |
| 2016-16 | October 2016 | The amendment eliminates the prohibition of recognizing current and deferred income taxes for an intra-entity asset transfer, other than inventory, until the asset has been sold to an outside party. The amendment will permit income tax consequences of such transfers to be recognized when the transfer occurs. | January 1, 2018 | Under assessment |
| 2016-18 | November 2016 | The amendment requires that restricted cash or restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning and end-of-period balances in the statement of cash flows. | January 1, 2018 | Under assessment |
| 2017-01 | January 2017 | The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. | January 1, 2018 | Under assessment |

## 4. Business Combinations

### Acquisition of Great Lakes Power

On October 31, 2016, Hydro One acquired Great Lakes Power, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure Holdings Inc. The total purchase price for Great Lakes Power was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. The following table summarizes the determination of the final fair value of the assets acquired and liabilities assumed:

| *(millions of dollars)* | |
|---|---|
| Cash and cash equivalents | 5 |
| Property, plant and equipment | 221 |
| Intangible assets | 1 |
| Regulatory assets | 50 |
| Goodwill | 159 |
| Working capital | (2) |
| Long-term debt | (186) |
| Pension and post-employment benefit liabilities, net | (5) |
| Deferred income taxes | (17) |
| | 226 |

Goodwill of approximately $159 million arising from the Great Lakes Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Great Lakes Power. Great Lakes Power contributed revenues of

$6 million and less than $1 million of net income to the Company's consolidated financial results for the year ended December 31, 2016. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Great Lakes Power's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2016 and therefore, has not been disclosed on a pro forma basis. On January 16, 2017, the name of Great Lakes Power was changed to Hydro One Sault Ste. Marie LP.

## Agreement to Purchase Orillia Power

On August 15, 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

## Acquisition of Woodstock Hydro

On October 31, 2015, Hydro One acquired Woodstock Hydro Holdings Inc. (Woodstock Hydro), an electricity distribution company located in southwestern Ontario. The total purchase price for Woodstock Hydro was approximately $32 million. The purchase price was finalized and the Company made the final purchase price payment of $3 million in 2016. The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

| *(millions of dollars)* | |
|---|---|
| Working capital | 4 |
| Property, plant and equipment | 27 |
| Intangible assets | 1 |
| Deferred income tax assets | 2 |
| Goodwill | 22 |
| Long-term debt | (17) |
| Derivative instruments | (3) |
| Post-retirement and post-employment benefit liability | (1) |
| Regulatory liabilities | (1) |
| Other long-term liabilities | (2) |
| | 32 |

Goodwill of approximately $22 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.

## Acquisition of Haldimand Hydro

On June 30, 2015, Hydro One acquired Haldimand County Utilities Inc. (Haldimand Hydro), an electricity distribution company located in southwestern Ontario. The total purchase price for Haldimand Hydro was approximately $73 million. The purchase price was finalized in 2016. The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

| *(millions of 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 |

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.

### 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; and
- 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.

As a result of the spin-off, goodwill related to Hydro One Brampton of $60 million was eliminated from the Consolidated Balance Sheet.

## 5. Depreciation And Amortization

| *Year ended December 31*<br>*(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Depreciation of property, plant and equipment | **612** | 595 |
| Asset removal costs | **90** | 91 |
| Amortization of intangible assets | **56** | 54 |
| Amortization of regulatory assets | **20** | 19 |
| | **778** | 759 |

## 6. Financing Charges

| *Year ended December 31*<br>*(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Interest on long-term debt | **424** | 417 |
| Interest on short-term notes | **9** | 2 |
| Other | **16** | 14 |
| Less: Interest capitalized on construction and development in progress | **(54)** | (52) |
| Interest earned on investments | **(2)** | (3) |
| Gain on interest-rate swap agreements | **–** | (2) |
| | **393** | 376 |

## 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*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Income taxes / provision for PILs at statutory rate | 235 | 217 |
| Increase (decrease) resulting from: | | |
| Net temporary differences recoverable in future rates charged to customers: | | |
| Capital cost allowance in excess of depreciation and amortization | (53) | (37) |
| Pension contributions in excess of pension expense | (16) | (25) |
| Overheads capitalized for accounting but deducted for tax purposes | (16) | (15) |
| Interest capitalized for accounting but deducted for tax purposes | (14) | (13) |
| Environmental expenditures | (5) | (5) |
| Other | 5 | (6) |
| Net temporary differences | (99) | (101) |
| Net tax benefit resulting from transition from PILs Regime to Federal Tax Regime | – | (19) |
| Hydro One Brampton spin-off | – | 7 |
| Net permanent differences | 3 | 1 |
| Total income taxes / provision for PILs | 139 | 105 |

The major components of income tax expense are as follows:

| *Year ended December 31*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Current income taxes / provision for PILs | 25 | 2,949 |
| Deferred income taxes / provision for (recovery of) PILs | 114 | (2,844) |
| Total income taxes / provision for PILs | 139 | 105 |
| Effective income tax rate | 15.7% | 12.8% |

The provision for current income taxes / PILs is remitted to the CRA (Federal Tax Regime) and the OEFC (PILs Regime). At December 31, 2016, $14 million (2015 – $1 million) receivable from the CRA was included in other current assets and $6 million (2015 – $12 million) receivable from the OEFC was included in due from related parties on the Consolidated Balance Sheet.

In connection with the IPO in 2015, 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 in 2015 (see note 21). Hydro One used the proceeds of this share subscription to pay the Departure Tax.

The 2015 total income taxes / provision for PILs included a current provision of $2,600 million and a deferred recovery of $2,810 million resulting from the transition from the PILs Regime to the Federal Tax Regime. The deferred recovery was not included in the rate-setting process. Deferred income tax 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, 2016 and 2015, deferred income tax assets and liabilities consisted of the following:

| *December 31*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| **Deferred income tax assets** | | |
| Depreciation and amortization in excess of capital cost allowance | 495 | 937 |
| Non-depreciable capital property | 271 | 271 |
| Post-retirement and post-employment benefits expense in excess of cash payments | 607 | 578 |
| Environmental expenditures | 74 | 75 |
| Non-capital losses | 213 | 62 |
| Investment in subsidiaries | 75 | 55 |
| Other | 30 | 10 |
| | 1,765 | 1,988 |
| Less: valuation allowance | (352) | (333) |
| Total deferred income tax assets | 1,413 | 1,655 |
| Less: current portion | – | 19 |
| | 1,413 | 1,636 |

| *December 31*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| **Deferred income tax liabilities** | | |
| Regulatory amounts that are not recognized for tax purposes | (153) | (153) |
| Goodwill | (10) | (10) |
| Capital cost allowance in excess of depreciation and amortization | (64) | (42) |
| Other | (11) | (2) |
| Total deferred income tax liabilities | (238) | (207) |
| Less: current portion | – | – |
| | (238) | (207) |
| Net deferred income tax assets | 1,175 | 1,448 |

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

| *December 31*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Current: | | |
| Other current assets | – | 19 |
| Long-term: | | |
| Deferred income tax assets | 1,235 | 1,636 |
| Deferred income tax liabilities | (60) | (207) |
| Net deferred income tax assets | 1,175 | 1,448 |

The valuation allowance for deferred tax assets as at December 31, 2016 was $352 million (2015 – $333 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2016, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

| *Year of expiry* *(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| 2034 | **2** | 2 |
| 2035 | **222** | 232 |
| 2036 | **580** | – |
| Total losses | **804** | 234 |

## 8. Accounts Receivable

| *December 31* *(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Accounts receivable – billed | **431** | 379 |
| Accounts receivable – unbilled | **442** | 458 |
| Accounts receivable, gross | **873** | 837 |
| Allowance for doubtful accounts | **(35)** | (61) |
| Accounts receivable, net | **838** | 776 |

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2016 and 2015:

| *Year ended December 31* *(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Allowance for doubtful accounts – January 1 | **(61)** | (66) |
| Write-offs | **37** | 37 |
| Additions to allowance for doubtful accounts | **(11)** | (32) |
| Allowance for doubtful accounts – December 31 | **(35)** | (61) |

## 9. Other Current Assets

| *December 31* *(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Regulatory assets *(Note 12)* | **37** | 36 |
| Materials and supplies | **19** | 21 |
| Deferred income tax assets *(Notes 3, 7)* | **–** | 19 |
| Prepaid expenses and other assets | **46** | 29 |
| | **102** | 105 |

## 10. Property, Plant And Equipment

| *December 31, 2016* *(millions of dollars)* | Property, Plant and Equipment | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| Transmission | 14,692 | 4,862 | 910 | 10,740 |
| Distribution | 9,656 | 3,305 | 243 | 6,594 |
| Communication | 1,233 | 777 | 20 | 476 |
| Administration and service | 1,632 | 924 | 61 | 769 |
| Easements | 628 | 67 | – | 561 |
| | 27,841 | 9,935 | 1,234 | 19,140 |

| *December 31, 2015* *(millions of dollars)* | Property, Plant and Equipment | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| Transmission | 13,704 | 4,621 | 853 | 9,936 |
| Distribution | 9,205 | 3,177 | 238 | 6,266 |
| Communication | 1,165 | 704 | 28 | 489 |
| Administration and service | 1,531 | 848 | 36 | 719 |
| Easements | 622 | 64 | – | 558 |
| | 26,227 | 9,414 | 1,155 | 17,968 |

Financing charges capitalized on property, plant and equipment under construction were $52 million in 2016 (2015 – $50 million).

## 11. Intangible Assets

| *December 31, 2016* *(millions of dollars)* | Intangible Assets | Accumulated Amortization | Development in Progress | Total |
|---|---|---|---|---|
| Computer applications software | 621 | 326 | 53 | 348 |
| Other | 5 | 4 | – | 1 |
| | 626 | 330 | 53 | 349 |

| *December 31, 2015* *(millions of dollars)* | Intangible Assets | Accumulated Amortization | Development in Progress | Total |
|---|---|---|---|---|
| Computer applications software | 579 | 270 | 24 | 333 |
| Other | 7 | 4 | – | 3 |
| | 586 | 274 | 24 | 336 |

Financing charges capitalized to intangible assets under development were $2 million in 2016 (2015 – $1 million). The estimated annual amortization expense for intangible assets is as follows: 2017 – $54 million; 2018 – $54 million; 2019 – $45 million; 2020 – $27 million; and 2021 – $26 million.

## 12. 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*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| **Regulatory assets:** | | |
| Deferred income tax regulatory asset | 1,587 | 1,445 |
| Pension benefit regulatory asset | 900 | 952 |
| Post-retirement and post-employment benefits | 243 | 240 |
| Environmental | 204 | 207 |
| Retail settlement variance account | 145 | 110 |
| Debt premium | 32 | – |
| Share-based compensation | 31 | 10 |
| Distribution system code exemption | 10 | 10 |
| 2015-2017 rate rider | 7 | 20 |
| B2M LP start-up costs | 5 | 8 |
| Pension cost variance | 4 | 37 |
| Other | 14 | 12 |
| Total regulatory assets | 3,182 | 3,051 |
| Less: current portion | 37 | 36 |
| | 3,145 | 3,015 |
| **Regulatory liabilities:** | | |
| Green Energy expenditure variance | 69 | 76 |
| External revenue variance | 64 | 87 |
| CDM deferral variance | 54 | 53 |
| Deferred income tax regulatory liability | 4 | 23 |
| Other | 18 | 16 |
| Total regulatory liabilities | 209 | 255 |
| Less: current portion | – | 19 |
| | 209 | 236 |

### 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 2016 income tax expense would have been higher by approximately $104 million (2015 – $101 million).

### Pension Benefit Regulatory Asset

In accordance with OEB rate orders, pension costs are recovered 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, 2016 OCI would have been higher by $52 million (2015 – $284 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 re-measurement adjustment. In the absence of rate-regulated accounting, 2016 OCI would have been lower by $3 million (2015 – higher by $33 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 2016, the environmental regulatory asset decreased by $1 million (2015 – $24 million) to reflect related changes in the Company's PCB liability, and increased by $10 million (2015 – $1 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, 2016 operation, maintenance and administration expenses would have been higher by $9 million (2015 – lower by $23 million). In addition, 2016 amortization expense would have been lower by $20 million (2015 – $19 million), and 2016 financing charges would have been higher by $8 million (2015 – $10 million).

## Retail Settlement Variance Account (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.

## Debt Premium

The value of debt assumed in the acquisition of Great Lakes Power has been recorded at fair value in accordance with US GAAP – Business Combinations. The OEB allows for recovery of interest at the coupon rate of the Senior Secured Bonds and a regulatory asset has been recorded for the difference between the fair value and face value of this debt. The debt premium is recovered over the remaining term of the debt (see note 15).

## Share-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2016 operation, maintenance and administration expenses would have been higher by $9 million (2015 – $5 million).

## Distribution System Code (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 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 is being recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2015 or 2016.

## 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 is being disposed in accordance with the OEB decision over a 32-month period ending on December 31, 2017.

## 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 are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

## 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 is being recovered through the 2015-2017 Rate Rider. In the absence of rate-regulated accounting, 2016 revenue would have been higher by $25 million (2015 – lower by $6 million).

### 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.

### 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 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirements, respectively. There were no additions to this regulatory account in 2016.

## 13. Accounts Payable and Other Current Liabilities

| *December 31*<br>*(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Accounts payable | **181** | 155 |
| Accrued liabilities | **659** | 598 |
| Accrued interest | **105** | 96 |
| Regulatory liabilities *(Note 12)* | **–** | 19 |
| | **945** | 868 |

## 14. Other Long-Term Liabilities

| *December 31*<br>*(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Post-retirement and post-employment benefit liability *(Note 18)* | **1,641** | 1,560 |
| Pension benefit liability *(Note 18)* | **900** | 952 |
| Environmental liabilities *(Note 19)* | **177** | 185 |
| Asset retirement obligations *(Note 20)* | **9** | 9 |
| Long-term accounts payable and other liabilities | **25** | 17 |
| | **2,752** | 2,723 |

## 15. 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 up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

On August 15, 2016, Hydro One Inc. terminated its $1.5 billion revolving standby credit facility maturing in June 2020 and its $800 million three-year senior, revolving term credit facility maturing in October 2018 (collectively Prior Credit Facilities). On the same date, Hydro One Inc. entered into a new credit agreement for a $2.3 billion revolving credit facility maturing in June 2021 (New Credit Facility). The New Credit Facility ranks equally with any existing and future senior debt of Hydro One Inc., and has customary covenants substantially similar to the covenants under the Prior Credit Facilities. In addition, on November 7, 2016, the maturity date of Hydro One's $250 million credit facility was extended from November 2020 to November 2021.

At December 31, 2016, Hydro One's consolidated committed, unsecured and undrawn credit facilities totalling $2,550 million consisted of the following:

| *(millions of dollars)* | Maturity | Amount |
|---|---|---|
| Hydro One Inc. | | |
| Revolving standby credit facility | June 2021 | 2,300 |
| Hydro One | | |
| Five-year senior, revolving term credit facility | November 2021 | 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 that no event of default has occurred or would result from such credit extension.

### Long-Term Debt

At December 31, 2016, $10,523 million 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 under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At December 31, 2016, $1.2 billion remained available for issuance until January 2018. In addition, at December 31, 2016, the Company had long-term debt of $184 million assumed as part of the Great Lakes Power acquisition.

The following table presents outstanding long-term debt at December 31, 2016 and 2015:

| *December 31*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| 4.64% Series 10 notes due 2016 | – | 450 |
| Floating-rate Series 27 notes due 2016[1] | – | 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[1] | 228 | 228 |
| 1.48% Series 37 notes due 2019[2] | 500 | – |
| 4.40% Series 20 notes due 2020 | 300 | 300 |
| 1.62% Series 33 notes due 2020[2] | 350 | 350 |
| 1.84% Series 34 notes due 2021 | 500 | – |
| 3.20% Series 25 notes due 2022 | 600 | 600 |
| 2.77% Series 35 notes due 2026 | 500 | – |
| 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 |
| 3.91% Series 36 notes due 2046 | 350 | – |
| 3.72% Series 38 notes due 2047 | 450 | – |
| 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 |
| Hydro One Inc. long-term debt | 10,523 | 8,723 |
| 6.6% Senior Secured Bonds due 2023 (Face value – $112 million) | 144 | – |
| 4.6% Note Payable due 2023 (Face value – $36 million) | 40 | – |
| Great Lakes Power long-term debt | 184 | – |
| | 10,707 | 8,723 |
| Add: Net unamortized debt premiums[3] | 15 | 17 |
| Add: Unrealized mark-to-market loss (gain)[2] | (2) | 1 |
| Less: Deferred debt issuance costs[3] | (40) | (34) |
| Total long-term debt | 10,680 | 8,707 |

[1] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

[2] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and $500 million Series 37 notes due 2019 (2015 – loss relates to $50 million of the Series 33 notes due 2020). The unrealized mark-to-market net gain is offset by a $2 million (2015 – $1 million) unrealized mark-to-market net loss (2015 – gain) on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See note 16 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[3] Effective January 1, 2016, deferred debt issuance costs and net unamortized debt premiums were reclassified from other long-term assets and other long-term liabilities, respectively, as an offset to long-term debt upon adoption of ASU 2015-03 (see note 3). Balances as at December 31, 2015 were updated to reflect the retrospective adoption of ASU 2015-03.

The total long-term debt is presented on the consolidated balance sheets as follows:

| *December 31* *(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Current liabilities: | | |
| Long-term debt payable within one year | 602 | 500 |
| Long-term liabilities: | | |
| Long-term debt | 10,078 | 8,207 |
| Total long-term debt | 10,680 | 8,707 |

In 2016, Hydro One issued $2,300 million (2015 – $350 million) of long-term debt under the MTN Program, and repaid $502 million (2015 – $550 million) of total long-term debt.

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 dollars)* | Weighted Average Interest Rate *(%)* |
|---|---|---|
| 1 year | 602 | 5.2 |
| 2 years | 753 | 2.8 |
| 3 years | 731 | 1.4 |
| 4 years | 653 | 2.9 |
| 5 years | 503 | 1.9 |
| | 3,242 | 2.8 |
| 6 – 10 years | 1,234 | 3.3 |
| Over 10 years | 6,195 | 5.2 |
| | 10,671 | 4.3 |

Interest payment obligations related to long-term debt are summarized by year in the following table:

| Year | Interest Payments *(millions of dollars)* |
|---|---|
| 2017 | 456 |
| 2018 | 425 |
| 2019 | 402 |
| 2020 | 384 |
| 2021 | 370 |
| | 2,037 |
| 2022-2026 | 1,703 |
| 2027+ | 4,405 |
| | 8,145 |

## 16. 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, 2016 and 2015, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, 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, 2016 and 2015 are as follows:

| *December 31*<br>*(millions of dollars)* | 2016<br>Carrying Value | 2016<br>Fair Value | 2015<br>Carrying Value | 2015<br>Fair Value |
|---|---|---|---|---|
| Long-term debt | | | | |
| $50 million of MTN Series 33 notes | 50 | 50 | 51 | 51 |
| $500 million of MTN Series 37 notes | 498 | 498 | – | – |
| Other notes and debentures | 10,132 | 11,462 | 8,656 | 9,942 |
| | 10,680 | 12,010 | 8,707 | 9,993 |

## Fair Value Measurements of Derivative Instruments

At December 31, 2016, Hydro One Inc. had interest-rate swaps in the amount of $550 million (2015 – $50 million) that was used to convert fixed-rate debt to floating-rate debt. These swaps are classified as a fair value hedges. Hydro One Inc.'s fair value hedge exposure was equal to about 5% (2015 – 1%) of its total long-term debt. At December 31, 2016, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- 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; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At December 31, 2016 and 2015, the Company had no interest-rate swaps classified as undesignated contracts.

## Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2016 and 2015 is as follows:

| *December 31, 2016*<br>*(millions of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| Assets: | | | | | |
| Cash and cash equivalents | 50 | 50 | 50 | – | – |
| | 50 | 50 | 50 | – | – |
| Liabilities: | | | | | |
| Short-term notes payable | 469 | 469 | 469 | – | – |
| Long-term debt, including current portion | 10,680 | 12,010 | – | 12,010 | – |
| Derivative instruments | | | | | |
| Fair value hedges – interest-rate swaps | 2 | 2 | 2 | – | – |
| | 11,151 | 12,481 | 471 | 12,010 | – |

| December 31, 2015 (millions of 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, including current portion | 8,707 | 9,993 | – | 9,993 | – |
| | 10,198 | 11,484 | 1,491 | 9,993 | – |

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 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, 2016 and 2015.

## 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. The Company is not currently exposed to material commodity price risk or material foreign exchange 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. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in 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, 2016 or 2015.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument 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, 2016 and 2015 was not significant.

### Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2016 and 2015, 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, 2016 and 2015, there was no significant accounts receivable balance due from any single customer.

At December 31, 2016, the Company's provision for bad debts was $35 million (2015 – $61 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2016, approximately 6% (2015 – 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; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current 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, 2016 and 2015, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not significant. At December 31, 2016, 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 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 credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

At December 31, 2016, accounts payable and accrued liabilities in the amount of $840 million (2015 – $753 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

## 17. 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. At December 31, 2016 and 2015, the Company's capital structure was as follows:

| *December 31*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Long-term debt payable within one year | **602** | 500 |
| Short-term notes payable | **469** | 1,491 |
| Less: cash and cash equivalents | **50** | 94 |
| | **1,021** | 1,897 |
| Long-term debt | **10,078** | 8,207 |
| Preferred shares | **418** | 418 |
| Common shares | **5,623** | 5,623 |
| Retained earnings | **3,950** | 3,806 |
| Total capital | **21,090** | 19,951 |

Hydro One Inc. and Great Lakes Power have customary covenants typically associated with long-term debt. Hydro One Inc.'s long-term debt and credit facility covenants limit 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, 2016, Hydro One Inc. and Great Lakes Power were in compliance with all covenants and limitations.

## 18. Pension and Post-retirement and Post-employment Benefits

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplementary pension plan, and post-retirement and post-employment benefit plans.

### Defined Contribution Pension Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan is mandatory and covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One contributions to the DC Plan for the year ended December 31, 2016 were less than $1 million (2015 – $nil). At December 31, 2016, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2015 – $nil).

## Defined Benefit Pension Plan, Supplementary Pension Plan, and Post-Retirement and Post-Employment Plans

The Pension Plan is a defined benefit contributory plan which covers all regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For Management employees who commenced employment on or after January 1, 2004, and for 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. Membership in the Pension Plan was closed to Management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2016 of $108 million (2015 – $177 million) were based on an actuarial valuation effective December 31, 2015 (2015 – based on an actuarial valuation effective December 31, 2013) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2017 and 2018 are approximately $105 million and $102 million, respectively, based on the actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings.

Future minimum contributions beyond 2018 will be based on an actuarial valuation effective no later than December 31, 2018. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Hydro One Supplemental Pension Plan (Supplemental 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 Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

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 dollars)* | **2016** | 2015 | **2016** | 2015 |
| **Change in projected benefit obligation** | | | | |
| Projected benefit obligation, beginning of year | **7,683** | 7,535 | **1,610** | 1,582 |
| Current service cost | **144** | 146 | **42** | 43 |
| Employee contributions | **45** | 40 | **–** | – |
| Interest cost | **308** | 302 | **67** | 64 |
| Benefits paid | **(354)** | (334) | **(43)** | (47) |
| Net actuarial loss (gain) | **(52)** | (6) | **14** | (27) |
| Change due to Hydro One Brampton spin-off | **–** | – | **–** | (5) |
| Projected benefit obligation, end of year | **7,774** | 7,683 | **1,690** | 1,610 |
| **Change in plan assets** | | | | |
| Fair value of plan assets, beginning of year | **6,731** | 6,299 | **–** | – |
| Actual return on plan assets | **370** | 582 | **–** | – |
| Benefits paid | **(354)** | (334) | **(43)** | (47) |
| Employer contributions | **108** | 177 | **43** | 47 |
| Employee contributions | **45** | 40 | **–** | – |
| Administrative expenses | **(26)** | (33) | **–** | – |
| Fair value of plan assets, end of year | **6,874** | 6,731 | **–** | – |
| Unfunded status | **900** | 952 | **1,690** | 1,610 |

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

| *December 31* *(millions of dollars)* | Pension Benefits 2016 | 2015 | Post-Retirement and Post-Employment Benefits 2016 | 2015 |
|---|---|---|---|---|
| Other assets | 1[1] | – | – | – |
| Accrued liabilities | – | – | 56 | 50 |
| Pension benefit liability | 900 | 952 | – | – |
| Post-retirement and post-employment benefit liability | – | – | 1,641[2] | 1,560 |
| Net unfunded status | 899 | 952 | 1,697 | 1,610 |

[1] Represents the funded status of Great Lakes Power's defined benefit pension plan.

[2] Includes $7 million (2015 – $nil) relating to Great Lakes Power's post-employment benefit plans.

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 dollars)* | 2016 | 2015 |
|---|---|---|
| PBO | 7,774 | 7,683 |
| ABO | 7,094 | 7,020 |
| Fair value of plan assets | 6,874 | 6,731 |

On an ABO basis, the Pension Plan was funded at 97% at December 31, 2016 (2015 – 96%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2016 (2015 – 88%). 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, 2016 and 2015 for the Pension Plan:

| *Year ended December 31* *(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Current service cost, net of employee contributions | 144 | 146 |
| Interest cost | 308 | 302 |
| Expected return on plan assets, net of expenses | (432) | (406) |
| Amortization of actuarial losses | 96 | 119 |
| Prior service cost amortization | – | 2 |
| Net periodic benefit costs | 116 | 163 |
| Charged to results of operations[1] | 48 | 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, 2016, pension costs of $108 million (2015 – $177 million) were attributed to labour, of which $48 million (2015 – $81 million) was charged to operations, and $60 million (2015 – $96 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, 2016 and 2015 for the post-retirement and post-employment benefit plans:

| *Year ended December 31*<br>*(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Current service cost, net of employee contributions | 42 | 43 |
| Interest cost | 67 | 64 |
| Amortization of actuarial losses | 15 | 14 |
| Prior service cost amortization | – | – |
| Net periodic benefit costs | 124 | 121 |
| Charged to results of operations | 55 | 55 |

## 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, 2016 and 2015:

| | Pension Benefits | | Post-Retirement and Post-Employment Benefits | |
|---|---|---|---|---|
| *Year ended December 31* | 2016 | 2015 | 2016 | 2015 |
| Significant assumptions: | | | | |
| Weighted average discount rate | 3.90% | 4.00% | 3.90% | 4.10% |
| Rate of compensation scale escalation (long-term) | 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] 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031 (2015 – 6.38% in 2016, 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, 2016 and 2015. 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* | 2016 | 2015 |
|---|---|---|
| Pension Benefits: | | |
| Weighted average expected rate of return on plan assets | 6.50% | 6.50% |
| Weighted average discount rate | 4.00% | 4.00% |
| Rate of compensation scale escalation (long-term) | 2.50% | 2.50% |
| Rate of cost of living increase | 2.00% | 2.00% |
| Average remaining service life of employees *(years)* | 15 | 13 |
| Post-Retirement and Post-Employment Benefits: | | |
| Weighted average discount rate | 4.10% | 4.00% |
| Rate of compensation scale escalation (long-term) | 2.50% | 2.50% |
| Rate of cost of living increase | 2.00% | 2.00% |
| Average remaining service life of employees *(years)* | 15.3 | 13.8 |
| 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 (2015 – 6.52% in 2015, grading down to 4.36% 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, 2016 and 2015 is as follows:

| *December 31*<br>*(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Projected benefit obligation: | | |
| Effect of a 1% increase in health care cost trends | **289** | 252 |
| Effect of a 1% decrease in health care cost trends | **(221)** | (196) |

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, 2016 and 2015 is as follows:

| *Year ended December 31*<br>*(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Service cost and interest cost: | | |
| Effect of a 1% increase in health care cost trends | **23** | 22 |
| 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, 2016 and 2015:

| **December 31, 2016 Life expectancy at 65 for a member currently at** | | | | December 31, 2015 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 |
| **22** | **24** | **23** | **24** | 23 | 25 | 24 | 26 |

## Estimated Future Benefit Payments

At December 31, 2016, estimated future benefit payments to the participants of the Plans were:

| *(millions of dollars)* | **Pension Benefits** | Post-Retirement and Post-Employment Benefits |
|---|---|---|
| 2017 | 321 | 56 |
| 2018 | 331 | 57 |
| 2019 | 340 | 60 |
| 2020 | 349 | 62 |
| 2021 | 358 | 64 |
| 2022 through to 2026 | 1,910 | 355 |
| Total estimated future benefit payments through to 2026 | 3,609 | 654 |

## 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* <br> *(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| **Pension Benefits:** | | |
| Actuarial loss (gain) for the year | **35** | (181) |
| Amortization of actuarial losses | **(96)** | (119) |
| Prior service cost amortization | **–** | (2) |
| | **(61)** | (302) |
| **Post-Retirement and Post-Employment Benefits:** | | |
| Actuarial loss (gain) for the year | **14** | (27) |
| Amortization of actuarial losses | **(15)** | (14) |
| Prior service cost amortization | **–** | – |
| | **(1)** | (41) |

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, 2016 and 2015:

| *Year ended December 31* <br> *(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| **Pension Benefits:** | | |
| Prior service cost | **–** | – |
| Actuarial loss | **900** | 952 |
| | **900** | 952 |
| **Post-Retirement and Post-Employment Benefits:** | | |
| Actuarial loss | **243** | 240 |
| | **243** | 240 |

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 dollars)* | **2016** | 2015 | **2016** | 2015 |
| Prior service cost | **–** | – | **–** | – |
| Actuarial loss | **79** | 96 | **6** | 8 |
| | **79** | 96 | **6** | 8 |

## 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, 2016, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

| | Target Allocation (%) | Pension Plan Assets (%) |
|---|---|---|
| Equity securities | 55.0 | 58.7 |
| Debt securities | 35.0 | 33.6 |
| Other[1] | 10.0 | 7.7 |
| | 100.0 | 100.0 |

[1] Other investments include real estate and infrastructure investments.

At December 31, 2016, the Pension Plan held $11 million (2015 – $9 million) Hydro One corporate bonds and $450 million (2015 – $420 million) of debt securities of the Province.

### 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, 2016 and 2015. 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, 2016 and 2015, 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, 2016 and 2015:

| *December 31, 2016 (millions of dollars)* | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Pooled funds | – | 20 | 425 | 445 |
| Cash and cash equivalents | 146 | – | – | 146 |
| Short-term securities | – | 127 | – | 127 |
| Corporate shares – Canadian | 911 | – | – | 911 |
| Corporate shares – Foreign | 2,985 | 113 | – | 3,098 |
| Bonds and debentures – Canadian | – | 1,943 | – | 1,943 |
| Bonds and debentures – Foreign | – | 193 | – | 193 |
| Total fair value of plan assets[1] | 4,042 | 2,396 | 425 | 6,863 |

[1] At December 31, 2016, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, $15 million of purchased investments payable, $9 million of pension administration expenses payable, and $7 million of sold investments receivable.

| *December 31, 2015* *(millions of dollars)* | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Pooled funds | – | 23 | 301 | 324 |
| Cash and cash equivalents | 191 | – | – | 191 |
| Short-term securities | – | 80 | – | 80 |
| Corporate shares – Canadian | 807 | – | – | 807 |
| Corporate shares – Foreign | 2,931 | 116 | – | 3,047 |
| Bonds and debentures – Canadian | – | 2,072 | – | 2,072 |
| Bonds and debentures – Foreign | – | 201 | – | 201 |
| Total fair value of plan assets[1] | 3,929 | 2,492 | 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.

See note 16 – 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, 2016 and 2015. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

| *Year ended December 31* *(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Fair value, beginning of year | **301** | 144 |
| Realized and unrealized gains | **23** | 51 |
| Purchases | **151** | 106 |
| Sales and disbursements | **(50)** | – |
| Fair value, end of year | **425** | 301 |

There were no significant transfers between any of the fair value levels during the years ended December 31, 2016 and 2015.

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 mainly consist 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 consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

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

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

## 19. Environmental Liabilities

The following tables show the movements in environmental liabilities for the years ended December 31, 2016 and 2015:

| *Year ended December 31, 2016* *(millions of dollars)* | PCB | Land Assessment and Remediation | Total |
|---|---|---|---|
| Environmental liabilities, January 1 | 148 | 59 | 207 |
| Interest accretion | 7 | 1 | 8 |
| Expenditures | (11) | (9) | (20) |
| Revaluation adjustment | (1) | 10 | 9 |
| Environmental liabilities, December 31 | 143 | 61 | 204 |
| Less: current portion | 18 | 9 | 27 |
| | 125 | 52 | 177 |

| *Year ended December 31, 2015* *(millions of 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 |

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, 2016* *(millions of dollars)* | PCB | Land Assessment and Remediation | Total |
|---|---|---|---|
| Undiscounted environmental liabilities | 158 | 66 | 224 |
| Less: discounting accumulated liabilities to present value | 15 | 5 | 20 |
| Discounted environmental liabilities | 143 | 61 | 204 |

| *December 31, 2015* *(millions of 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 |

At December 31, 2016, the estimated future environmental expenditures were as follows:

| *(millions of dollars)* | |
|---|---|
| 2017 | 27 |
| 2018 | 26 |
| 2019 | 25 |
| 2020 | 29 |
| 2021 | 36 |
| Thereafter | 81 |
| | 224 |

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 $158 million (2015 – $168 million). These expenditures are expected to be incurred over the period from 2017 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2016 to reduce the PCB environmental liability by $1 million (2015 – $24 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 $66 million (2015 – $61 million). These expenditures are expected to be incurred over the period from 2017 to 2032. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2016 to increase the land assessment and remediation environmental liability by $10 million (2015 – $1 million).

## 20. 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, 2016, Hydro One had recorded asset retirement obligations of $9 million (2015 – $9 million), primarily 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.

## 21. Share Capital

### Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2016 and 2015, the Company had 595 million 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.

### Common Share Offerings

In November 2015, Hydro One and the Province completed an initial public offering (IPO) on the Toronto Stock Exchange of approximately 15% of its 595 million outstanding common shares. In April 2016, the Province completed a secondary offering of approximately 83.3 million or 14% common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

### Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2016, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At December 31, 2016, 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, 2016, no preferred share dividends 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.

## 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, 2016.

| | | Preferred Shares | |
|---|---|---|---|
| *(millions of 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 totalling $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.

## 22. Dividends

In 2016, preferred share dividends in the amount of $19 million (2015 – $13 million) and common share dividends in the amount of $577 million (2015 – $875 million) were declared. The 2016 common share dividends include $77 million for the post-IPO period from November 5 to December 31, 2015, and $500 million for the year ended December 31, 2016.

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).

## 23. 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 stock-based compensation plans, including the share grant plans and the Long-term Incentive Plan, which are calculated using the treasury stock method.

| *Year ended December 31* | 2016 | 2015 |
|---|---|---|
| Net income attributable to common shareholders *(millions of dollars)* | 721 | 690 |
| Weighted average number of shares | | |
| Basic | 595,000,000 | 496,272,733 |
| Effect of dilutive stock-based compensation plans *(Note 24)* | 1,700,823 | 94,691 |
| Diluted | 596,700,823 | 496,367,424 |
| EPS | | |
| Basic | $1.21 | $1.39 |
| Diluted | $1.21 | $1.39 |

## 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, 2016 and 2015. 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 a different number of shares outstanding and held by the Province prior to the IPO. 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 comparable basis to evaluate the operations of the Company.

| *Year ended December 31* *(unaudited)* | 2016 | 2015 |
|---|---|---|
| Net income attributable to common shareholders *(millions of dollars)* | 721 | 690 |
| Pro forma weighted average number of common shares | | |
| Basic | 595,000,000 | 595,000,000 |
| Effect of dilutive stock-based compensation plans *(Note 24)* | 1,700,823 | 94,691 |
| Diluted | 596,700,823 | 595,094,691 |
| Pro forma adjusted non-GAAP EPS | | |
| Basic | $1.21 | $1.16 |
| Diluted | $1.21 | $1.16 |

The above pro forma adjusted non-GAAP basic and diluted EPS does not have any standardized meaning in US GAAP.

## 24. Stock-based Compensation

### Share Grant Plans

At December 31, 2016, Hydro One had two share grant plans (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 plan was 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 Hydro One Limited 2015 share grants of $111 million was 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. No shares were granted under the Share Grant Plans in 2016. Total share based compensation recognized during 2016 was $21 million (2015 – $10 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2016 and 2015 is presented below:

| *Year ended December 31, 2016* | Share Grants *(number of common shares)* | Weighted-Average Price |
|---|---|---|
| Share grants outstanding – January 1, 2016 | 5,412,354 | $20.50 |
| Granted (non-vested) | – | – |
| Forfeited | (77,939) | $20.50 |
| Share grants outstanding – December 31, 2016 | 5,334,415 | $20.50 |

| *Year ended December 31, 2015* | Share Grants *(number of common shares)* | Weighted-Average Price |
|---|---|---|
| Share grants outstanding – January 1, 2015 | – | – |
| Granted (non-vested) | 5,412,354 | $20.50 |
| Share grants outstanding – December 31, 2015 | 5,412,354 | $20.50 |

### 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.

| *Year ended December 31*<br>*(number of DSUs)* | 2016 | 2015 |
|---|---|---|
| DSUs outstanding – January 1 | 20,525 | – |
| DSUs granted | 78,558 | 20,525 |
| DSUs outstanding – December 31 | 99,083 | 20,525 |

For the year ended December 31, 2016, an expense of $2 million (2015 – less than $1 million) was recognized in earnings with respect to the DSU Plan. At December 31, 2016, a liability of $2 million (December 31, 2015 – less than $1 million), related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $23.58 and is included in accrued liabilities on the Consolidated Balance Sheets.

## 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 matches 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. In 2016, Company contributions made under the ESOP were $2 million (2015 – $nil).

## Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One and its subsidiaries, 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 of Hydro One.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), 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.

During 2016, the Company granted awards under its LTIP, consisting of PSUs and RSUs, all of which are equity settled, as follows:

| *Year ended December 31, 2016* | Number of PSUs | Number of RSUs |
|---|---|---|
| Units outstanding – January 1, 2016 | – | – |
| Units granted | 235,420 | 258,970 |
| Units forfeited | (4,820) | (4,820) |
| Units outstanding – December 31, 2016 | 230,600 | 254,150 |

The grant date total fair value of the awards was $12 million (2015 – $nil). The compensation expense recognized by the Company relating to these awards during 2016 was $3 million (2015 – $nil).

# 25. Noncontrolling Interest

On December 16, 2014, 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, 2016 and 2015:

| *Year ended December 31, 2016* *(millions of dollars)* | Temporary Equity | Equity | Total |
|---|---|---|---|
| Noncontrolling interest – January 1, 2016 | 23 | 52 | 75 |
| Distributions to noncontrolling interest | (3) | (6) | (9) |
| Net income attributable to noncontrolling interest | 2 | 4 | 6 |
| Noncontrolling interest – December 31, 2016 | 22 | 50 | 72 |

| *Year ended December 31, 2015* *(millions of 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 |

## 26. Related Party Transactions

The Province is the majority shareholder of Hydro One. The IESO, Ontario Power Generation Inc. (OPG), OEFC, OEB, and Hydro One Brampton are related parties to Hydro One because they are controlled or significantly influenced by the Province.

| Related Party | Transaction | Year ended December 31 2016 *(millions of dollars)* | 2015 |
|---|---|---|---|
| Province[1] | Dividends paid | 451 | 888 |
| | Common shares issued[2] | – | 2,600 |
| | IPO costs subsequently reimbursed by the Province[3] | – | 7 |
| IESO | Power purchased | 2,096 | 2,318 |
| | Revenues for transmission services | 1,549 | 1,548 |
| | Distribution revenues related to rural rate protection | 125 | 127 |
| | Distribution revenues related to the supply of electricity to remote northern communities | 32 | 32 |
| | Funding received related to Conservation and Demand Management programs | 63 | 70 |
| OPG | Power purchased | 6 | 11 |
| | Revenues related to provision of construction and equipment maintenance services | 5 | 7 |
| | Costs expensed related to the purchase of services | 1 | 1 |
| OEFC | Payments in lieu of corporate income taxes[4] | – | 2,933 |
| | Power purchased from power contracts administered by the OEFC | 1 | 6 |
| | Indemnification fee paid (terminated effective October 31, 2015) | – | 8 |
| OEB | OEB fees | 11 | 12 |
| Hydro One Brampton[1] | Revenues from management, administrative and smart meter network services | 3 | 1 |

[1] On August 31, 2015, Hydro One Inc. completed the spin-off of its subsidiary, Hydro One Brampton, to the Province.

[2] On November 4, 2015, Hydro One issued common shares to the Province for proceeds of $2.6 billion.

[3] In 2015, Hydro One incurred certain IPO related expenses totalling $7 million, which were subsequently reimbursed to the Company by the Province.

[4] In 2015, Hydro One made PILs to the OEFC totalling $2.9 billion, including Departure Tax of $2.6 billion.

Sales to and purchases from related parties are 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 dollars)* | 2016 | 2015 |
|---|---|---|
| Due from related parties | 158 | 191 |
| Due to related parties[1] | (147) | (138) |

[1] Included in due to related parties at December 31, 2016 are amounts owing to the IESO in respect of power purchases of $143 million (2015 – $134 million).

## 27. Consolidated Statements of Cash Flows

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

| *Year ended December 31* *(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Accounts receivable | (60) | 245 |
| Due from related parties | 33 | 33 |
| Materials and supplies | 2 | 2 |
| Prepaid expenses and other assets | (15) | 4 |
| Accounts payable | 19 | (23) |
| Accrued liabilities | 53 | (15) |
| Due to related parties | 9 | (89) |
| Accrued interest | 9 | (4) |
| Long-term accounts payable and other liabilities | 6 | – |
| Post-retirement and post-employment benefit liability | 78 | 60 |
| | 134 | 213 |

### Capital Expenditures

The following table reconciles 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 dollars)* | 2016 | 2015 |
|---|---|---|
| Capital investments in property, plant and equipment | (1,630) | (1,623) |
| Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment | 30 | 28 |
| Capital expenditures – property, plant and equipment | (1,600) | (1,595) |

The following table reconciles 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 dollars)* | 2016 | 2015 |
|---|---|---|
| Capital investments in intangible assets | (67) | (40) |
| Net change in accruals included in capital investments in intangible assets | 6 | 3 |
| Capital expenditures – intangible assets | (61) | (37) |

## 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 2016, capital contributions from these reassessments totalled $21 million (2015 – $57 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.

## Supplementary Information

| *Year ended December 31* <br> *(millions of dollars)* | **2016** | 2015 |
|---|---|---|
| Net interest paid | **418** | 416 |
| Income taxes / PILs paid | **32** | 2,933 |

# 28. 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.

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. A certification motion in the class action is pending. 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 2016, the Company paid approximately $1 million (2015 – $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.

# 29. Commitments

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

| *December 31, 2016* <br> *(millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter |
|---|---|---|---|---|---|---|
| Outsourcing agreements | 165 | 102 | 94 | 2 | 2 | 9 |
| Long-term software/meter agreement | 17 | 17 | 16 | 17 | 1 | 5 |
| Operating lease commitments | 11 | 10 | 6 | 10 | 3 | 2 |

### 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 agreement with Brookfield for these services expires in December 2024.

### Long-term software/meter agreement

Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

### 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, 2016, the Company made lease payments totalling $11 million (2015 – $7 million).

### Other Commitments

#### 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, 2016, Hydro One Inc. provided prudential support to the IESO on behalf of its subsidiaries using parental guarantees of $329 million (2015 – $329 million), and on behalf of a distributor using guarantees of $1 million (2015 – $1 million). In addition, as at December 31, 2016, Hydro One Inc. provided letters of credit in the amount of $24 million (2015 – $15 million), including $17 million (2015 – $15 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, 2016, Hydro One Inc. had letters of credit of $150 million (2015 – $139 million) outstanding relating to retirement compensation arrangements.

## 30. Segmented Reporting

Hydro One has three reportable segments:

- The Transmission Business, which comprises the transmission of 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 delivery of 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 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).

| *Year ended December 31, 2016* *(millions of dollars)* | Transmission | Distribution | Other | Consolidated |
|---|---|---|---|---|
| Revenues | 1,584 | 4,915 | 53 | 6,552 |
| Purchased power | – | 3,427 | – | 3,427 |
| Operation, maintenance and administration | 382 | 608 | 79 | 1,069 |
| Depreciation and amortization | 390 | 379 | 9 | 778 |
| Income (loss) before financing charges and income taxes | 812 | 501 | (35) | 1,278 |
| Capital investments | 988 | 703 | 6 | 1,697 |

| *Year ended December 31, 2015* *(millions of dollars)* | Transmission | Distribution | Other | Consolidated |
|---|---|---|---|---|
| Revenues | 1,536 | 4,949 | 53 | 6,538 |
| Purchased power | – | 3,450 | – | 3,450 |
| Operation, maintenance and administration | 414 | 633 | 88 | 1,135 |
| Depreciation and amortization | 374 | 380 | 5 | 759 |
| Income (loss) before financing charges and income taxes | 748 | 486 | (40) | 1,194 |
| Capital investments | 943 | 711 | 9 | 1,663 |

## Total Assets by Segment:

| *December 31* *(millions of dollars)* | 2016 | 2015 |
|---|---|---|
| Transmission | 13,007 | 12,045 |
| Distribution | 9,337 | 9,200 |
| Other | 3,007 | 3,049 |
| Total assets | 25,351 | 24,294 |

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

## 31. Subsequent Events

### Dividends

On February 9, 2017, preferred share dividends in the amount of $4 million and common share dividends in the amount of $125 million ($0.21 per common share) were declared.

# BOARD OF DIRECTORS
# & SENIOR LEADERSHIP TEAM


*For detailed biographical information of Hydro One Limited board members and senior leadership, go to*
▶ HydroOne.com/Investors

## BOARD OF DIRECTORS

1 **David Denison,** O.C., FCPA, FCA
Chair of the Board

2 **Ian Bourne,** ICD.D, F.ICD
Board Chair, Ballard Power Systems

3 **Charles Brindamour**
CEO, Intact Financial Corporation

4 **Marcello (Marc) Caira**
Vice Chairman,
Restaurants Brands International

5 **Christie Clark,** FCA, FCPA
Director, Loblaw Companies

6 **George Cooke**
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OMERS Administration Corp

7 **Margaret (Marianne) Harris**
Board Chair, IIROC

8 **James Hinds**
Former Board Chair, IESO and OPA

9 **Kathryn J. Jackson,** PH.D
Director, Portland General Electric

10 **Roberta Jamieson** O.C., C.M., I.P.C, LL.B, LL.D (HON)
President and CEO, Indspire

11 **Hon. Frances L. Lankin,** O.C., P.C., C.M.
Member of Senate of Canada

12 **Philip S. Orsino,** O.C., FCPA, FCA
Director, Bank of Montreal

13 **Jane Peverett,** FCMA, ICD.D
Director, Canadian Imperial
Bank of Commerce

14 **Gale Rubenstein**
Partner, Goodmans LLP

15 **Mayo Schmidt**
President and CEO, Hydro One Limited

## SENIOR LEADERSHIP TEAM

15 **Mayo Schmidt**
President and CEO

16 **Paul H. Barry**
EVP, Strategy
& Corporate Development

17 **Greg Kiraly**
Chief Operating Officer

18 **Judy McKellar**
EVP, Chief Human
Resources Officer

19 **Ferio Pugliese**
EVP, Customer Care
& Corporate Affairs

20 **James (Jamie) Scarlett**
EVP, Chief Legal Officer

21 **Michael Vels**
Chief Financial Officer

# CORPORATE & SHAREHOLDER INFORMATION

## CORPORATE OFFICES
483 Bay Street, South Tower
Toronto, Ontario, M5G 2P5
1.416.345.5000
www.HydroOne.com

## CUSTOMER INQUIRIES
Customer Service:
1.888.664.9376 or
CustomerCommunications@HydroOne.com
Report an Emergency (24 hours):
1.800.434.1235

## SHAREHOLDER SERVICES
If you are a registered shareholder and have inquiries regarding your account, wish to change your name or address, or have questions about dividends, duplicate mailings, lost stock certificates, share transfers or estate settlements, contact our transfer agent and registrar:
Computershare Trust Company of Canada
100 University Avenue, 8th Floor
Toronto, ON M5J 2Y1
1.514.982.7555 or 1.800.564.6253
service@computershare.com

## INSTITUTIONAL INVESTORS AND ANALYSTS
Institutional investors, securities analysts and others requiring additional financial information can visit HydroOne.com/Investors
or contact us at:
1.416.345.6867
Investor.Relations@HydroOne.com or
Bruce.Mann@HydroOne.com

## MEDIA INQUIRIES
1.416.345.6868 or 1.877.506.7584
Media.Relations@HydroOne.com

## SUSTAINABILITY
Hydro One is committed to continuing to grow responsibly and we focus our social and environmental sustainability efforts where we can make the most meaningful impacts on both. To learn more, visit HydroOne.com/OurCommitment

## STOCK EXCHANGE LISTING
Toronto Stock Exchange (TSX): H
(CUSIP #448811208)

H LISTED ON TMX Toronto Stock Exchange

## EQUITY INDEX INCLUSIONS
Dow Jones Select Utilities (Canada) Index
FTSE All-World Index Series
MSCI World (Canada) Index
S&P/TSX Composite Index
S&P/TSX Utilities Index
S&P/TSX Composite Dividend Index
S&P/TSX Composite Low Volatility Index

## DEBT SECURITIES
For details of the public debt securities of Hydro One and its subsidiaries, please refer to the *"Debt Information"* section under HydroOne.com/Investors

## INDEPENDENT AUDITORS
KPMG LLP

## ON-LINE INFORMATION
Hydro One is committed to open and full financial disclosure and best practices in corporate governance. We invite you to visit the Investor Relations section of HydroOne.com/InvestorRelations where you will find additional information about our business, including events and presentations, news releases, regulatory filings, governance practices, corporate social responsibility and our continuous disclosure materials, including quarterly financial releases, annual information forms and management information circulars. You may also subscribe to our news by email to automatically receive Hydro One news releases electronically.

## COMMON SHARE DIVIDEND INFORMATION
2017 Expected Dividend Dates

| Record Date*: | Payment Date*: |
|---|---|
| March 14, 2017 | March 31, 2017 |
| June 13, 2017 | June 30, 2017 |
| September 12, 2017 | September 29,2017 |
| December 12, 2017 | December 29, 2017 |

** Subject to Board approval*

Unless indicated otherwise, all common share dividends paid by Hydro One are designated as "eligible" dividends for the purposes of the *Income Tax Act* (Canada) and any similar provincial legislation.

## DIVIDEND REINVESTMENT PLAN (DRIP)
Hydro One offers a convenient dividend reinvestment program for eligible shareholders to purchase additional Hydro One shares by reinvesting their cash dividends without incurring brokerage or administration fees. For plan information and enrolment materials or to learn more about the Hydro One DRIP, visit HydroOne.com/DRIP or Computershare Trust Company of Canada at InvestorCentre.com/HydroOne

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**CAUTION REGARDING FORWARD-LOOKING INFORMATION AND OTHER RISKS**

This annual report includes forward-looking statements about the financial condition, plans and prospects of Hydro One that involve risks and uncertainties and non-GAAP measures that are detailed in the "Risk Management and Risk Factors", "Forward-Looking Statements and Information", and "Non-GAAP Measures" sections of the MD&A contained herein, which should be read in conjunction with all sections of this document.

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# DRAFT ISSUES LIST

To be determined at a later date.

# PROCEDURAL ORDERS/CORRESPONDENCE/NOTICES

Notices, Procedural Orders, and Correspondence will be filed after this Application is submitted.

# LIST OF WITNESSES

Hydro One Remote Communities Inc. is requesting a written hearing.

# CURRICULA VITAE

Remotes is requesting a written hearing. Curricula Vitae will be provided as required.

# Hydro One Remote Communities Inc.

# Distribution System Plan

2018 Cost of Service Application

Historical Period: 2013 to 2017

Forecast Period: 2018 to 2022

June 21, 2017

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# 1 Introduction

Hydro One Remote Communities Inc. ("**Remotes**") has prepared this Distribution System Plan ("**DSP**") in accordance with the Ontario Energy Board's ("**OEB**'s") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated March 28, 2013 (the "**Filing Requirements**") as part of its 4th Generation IR Application based on a 2018 forward test-year cost of service review ("**the Application**").

## 1.1 Objectives & Scope of Work

Remotes' DSP has been prepared to support the four key objectives from the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("**RRFE**"):

1. Customer Focus: services are provided in a manner that responds to identified customer preferences;
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3. Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

## 1.2 Outline of Report

This DSP has been organized using the same headings as the Filing Requirements, with the corresponding section number from the Filing Requirements included in brackets for each heading.

The report contains four sections, including this introductory section as Section 1. Section 2 provides a high-level overview of the DSP including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of Remotes' asset management process, including an overview of the assets managed and asset lifecycle optimization policies and practices. Section 4 provides a summary of Remotes' capital expenditure plan including an overview of the capital expenditure planning process, an assessment of the system capability for Renewable Energy Generation ("**REG**"), and justification of material projects.

## 1.3 Background & Drivers

Remotes' capital investments over the planning period have been aligned to the four categories of system access, system renewal, system service, and general plant. Table 1-1 summarizes Remotes' drivers for each investment category over the forecast period.

Table 1-1: Remotes' Investment Drivers over the Forecast Period

| Investment Category | Drivers | Projects/Activities |
|---|---|---|
| System access | Customer service requests | New customer connections and service upgrades<br>Fixed price layouts<br>Service cancellations |
| System renewal | Asset failure | Damage claims<br>Defective meter replacements |
| | Assets at the end of their service life due to failure risk | Small external demand requests<br>Distribution system improvements<br>Generator replacements<br>Generator overhauls<br>Diesel plant civil improvements<br>Day and bulk fuel tank replacements |
| System service | System capacity | Generator upgrades |
| | System reliability and operational efficiency | Supervisory Control and Data Acquisition ("**SCADA**") and Programmable Logic Controller ("**PLC**") upgrades |
| General plant | Non-system physical plant | Housing improvements<br>Storage buildings and miscellaneous civil projects<br>Minor fixed assets |

System access investments are modifications to Remotes' distribution system (including asset relocations) that Remotes performs to provide customers with access to electricity services via the distribution system.

System renewal investments involve replacing and/or refurbishing system assets to extend the service life of the assets and thereby maintain the ability of Remotes' distribution system and generation fleet to provide customers with electricity services at reasonable rates.

System service investments are modifications to Remotes' distribution system and generation assets to ensure that the system continues to meet Remotes' operational objectives, while addressing anticipated future customer electricity service requirements.

General plant investments are modifications, replacements, or additions to Remotes' assets that are not part of its distribution or generation system, including land and buildings, tools and equipment, rolling stock, Information Technology ("**IT**") equipment, and software used to support day-to-day business and operations activities.

## 1.4 Description of the Utility Company

Remotes is an integrated generation and distribution company licensed to generate and distribute electricity within 21 isolated communities in Northern Ontario. Remotes is entirely debt-financed and operates as a break-even company with no return on equity.

Remotes is driven by its corporate vision, mission, and business values. Together, they provide the basis to deliver on targeted performance objectives.

Figure 1-1: Remotes' Corporate Vision, Mission, and Values

**Corporate Vision:** "We will be the leading electrical utility and a trusted partner to remote communities in Ontario's North."

**Corporate Mission:** "We supply safe, reliable and affordable electricity to remote communities by focussing on continuous improvement, operational excellence and outstanding customer service."

**Corporate Values:**

- Employee and public safety;
- Customers and community relationships;
- Environmental sustainability;
- Business integrity;
- Teamwork;
- Actively engaged employees;
- Operational excellence;
- Innovative thinking; and
- Continuous improvement.

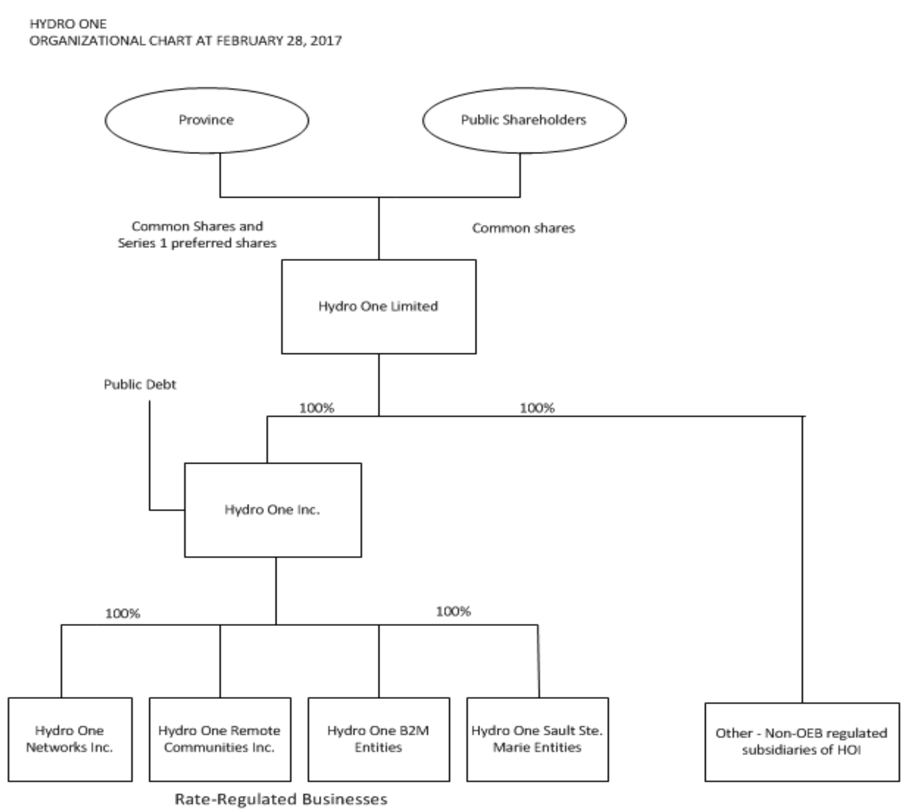
Remotes functions in a unique environment. Extremely low customer densities, a harsh climate, logistical challenges related to transportation, the absence of an integrated transmission system, and complex funding arrangements with third parties set Remotes apart from other Ontario distributors.

The communities served by Remotes are isolated and scattered across the Far North of Ontario. Thirteen communities are not accessible by year-round road and can be reached only by aircraft, winter roads or, in the case of one community, by barge, air, or winter road. The size and isolation of Remotes' service territory also means that the transportation and accommodation of staff, fuel, and equipment are key drivers of its costs. The company's reliance on winter roads for access to communities is also a major driver of work scheduling and completion activities, as scheduled projects may require deferral where winter roads cannot be constructed due to weather conditions, leading to project deferrals and the ensuing higher fuel and maintenance expenditures.

Remotes inherited Ontario Hydro's obligations to provide electricity to off-grid communities, which obligations were originally negotiated with the federal and provincial governments. Under these arrangements, the federal and provincial governments funded the original capital installation of facilities. In First Nation communities, the arrangements with the federal government ("the **Agreements**"), through Indigenous and Northern Affairs Canada ("**INAC**") remain in place. The Agreements specify that Remotes is responsible for funding the ongoing operation and maintenance of the system and that INAC is responsible for funding capital related to system expansions and capital upgrades. In the 1990s, INAC devolved responsibility for community infrastructure to First Nation communities. INAC now transfers funding to First Nations, who are responsible for administering most of the INAC's program funds. Therefore, Remotes' asset planning is a three-party process involving First Nation Band Councils, INAC, and Remotes. The timing and amount of funds available from INAC for funding upgrades is limited by overall funding constraints. Funding for new stations and larger engines must compete with other departmental priorities and may not be available in the year investment is required.

Remotes is wholly-owned by Hydro One Inc., which also owns 100% of Hydro One Networks Inc. Hydro One Inc. is, in turn, 100% owned by Hydro One Limited, whose ownership is split between public shareholders (through a Toronto Stock Exchange listing) and the Province of Ontario. As a subsidiary of Hydro One Inc., Remotes has access to operational, legal, regulatory, and financial expertise in the energy industry, and to leading technology and world-class expertise in innovation, engineering and design. As a small business, Remotes understands its customers and works closely with them.

Figure 1-2: Hydro One Inc. Corporate Structure



Remotes is licensed to provide both generation and distribution services outside of the competitive electricity market through its licences ED-2003-0037 and EG-2003-0138, which identify its service territory and generation facilities. Remotes is obligated to maintain system integrity and to comply with codes, legislation, regulations, and market rules. However, Remotes is exempt from certain requirements that are not applicable to its operations due to the unique nature of its business.

### 1.4.1 Service Area including Map

Remotes' service territory is spread out across Northern Ontario, as depicted in Figure 1-3. Remotes is currently licensed to generate and distribute within 21 isolated communities. These communities are shown in red in Figure 1-3 Collins and Whitesand, which are served via the Armstrong distribution system. Fifteen of these communities are First Nation communities, and thirteen are air access only.

Figure 1-3: Map of Remotes Service Territory


Three additional communities are anticipated to be added to Remotes' service area in the years 2018 to 2020: Cat Lake, Pikangikum, and Wunnumin Lake.

Table 1-2: List of Communities Serviced by Remotes

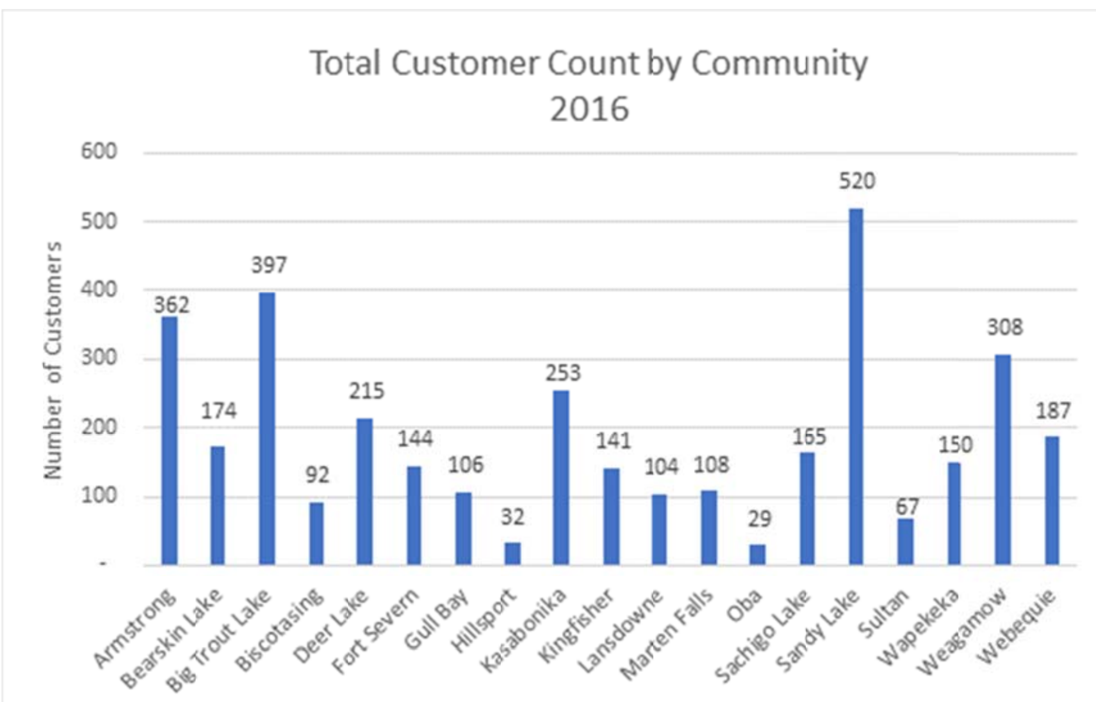
| **Presently Served by Remotes** | | |
|---|---|---|
| Armstrong | Gull Bay | Sachigo Lake |
| Bearskin Lake | Hillsport | Sandy Lake |
| Big Trout Lake | Kasabonika Lake | Sultan |
| Biscotasing | Kingfisher Lake | Wapekeka |
| Collins* | Lansdowne House | Weagamow |
| Deer Lake | Marten Falls | Webequie |
| Fort Severn | Oba | Whitesand* |
| **Anticipated to be Served by Remotes in the Near Term** | | |
| Cat Lake (2018) | Pikangikum (2019) | Wunnumin (2020) |

**Energy for Collins and Whitesand is provided from Armstrong*

## 1.4.2 Electricity Distribution

Remotes' 19 self-sufficient, stand-alone generation/distribution systems serve a total of 3,554 customers based on the 2016 year-end count. Figure 1-4 depicts the customer counts across those 19 systems. Customers in Collins and Whitesand are included in the Armstrong count.

Figure 1-4: Customer Count by Community in 2016



These communities are expected to grow slightly over the forecast period, as shown in Table 1-3. The largest anticipated customer increase is due to the three new communities which are expected to join Remotes' service area over the forecast period: Cat Lake (2018), Pikangikum (2019) and Wunnumin Lake (2020).

Table 1-3: Forecast Customer Counts in the Years 2017 to 2022 by Community

| Year | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| Armstrong | 366 | 367 | 370 | 372 | 374 | 377 |
| Bearskin Lake | 180 | 182 | 184 | 186 | 189 | 191 |
| Big Trout Lake | 403 | 405 | 409 | 413 | 417 | 421 |
| Biscotasing | 94 | 95 | 96 | 96 | 97 | 98 |
| Cat Lake | - | 110 | 114 | 118 | 122 | 126 |
| Deer Lake | 224 | 225 | 226 | 226 | 228 | 228 |
| Fort Severn | 149 | 151 | 153 | 156 | 158 | 160 |
| Gull Bay | 107 | 107 | 108 | 108 | 108 | 109 |
| Hillsport | 32 | 33 | 33 | 33 | 34 | 34 |
| Kasabonika | 264 | 267 | 274 | 280 | 286 | 293 |
| Kingfisher | 144 | 144 | 144 | 144 | 144 | 144 |
| Lansdowne | 105 | 106 | 106 | 106 | 107 | 107 |
| Marten Falls | 113 | 116 | 121 | 125 | 131 | 135 |
| Oba | 30 | 31 | 31 | 31 | 32 | 32 |
| Pikangikum | - | - | 531 | 533 | 538 | 541 |
| Sachigo Lake | 170 | 171 | 172 | 172 | 174 | 175 |
| Sandy Lake | 525 | 527 | 531 | 533 | 538 | 541 |
| Sultan | 68 | 68 | 69 | 69 | 70 | 71 |
| Wapekeka | 151 | 151 | 151 | 151 | 151 | 151 |
| Weagamow | 311 | 312 | 315 | 319 | 322 | 324 |
| Webequie | 191 | 194 | 198 | 203 | 207 | 211 |
| Wunnumin | - | - | - | 175 | 178 | 180 |
| **Total** | **3,627** | **3,762** | **4,336** | **4,549** | **4,605** | **4,649** |

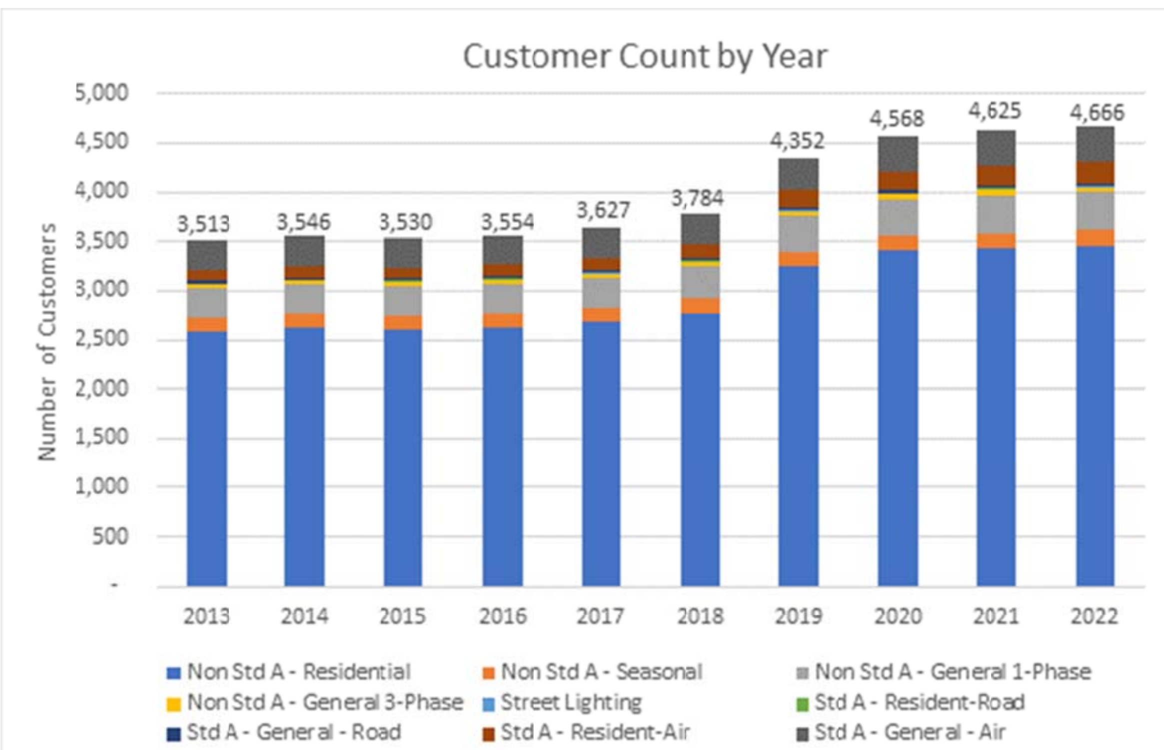
*O. Reg. 442/01*, a provincial regulation under the *Ontario Energy Board Act, 1998,* sets out two broad categories of customers that Remotes serves: customers who receive Rural or Remote Rate Protection ("**RRRP**") (which includes residential, General Service, and street lighting "**Non-Standard A**" customers); and customers occupying government premises, defined as customers who receive direct or indirect funding from government ("**Standard A**" customers). Standard A customers include the Ontario Ministry of Transportation, Health Canada, and INAC. Customer classes in this category are defined depending on the access to the community (air or road) and the type of service (residential or General Service). Non-Standard A customers are all other residents and businesses who received subsidized rates through the RRRP. The Non-Standard A customers are grouped by the type of service: residential or General Service. Residential customer classes are divided into seasonal and year-round, while General Service customer classes are divided into single-phase and three-phase service. Table 1-4 summarizes the definitions of the customer classes served by Remotes.

Table 1-4: Summary of Customer Classes Served by Remotes

| Customer Type | Definition | Customer Classes |
|---|---|---|
| Standard A | Government-funded (e.g. Health Canada, INAC) | Residential – air access<br>Residential – road access<br>General Service – air access<br>General Service – road access |
| Non-Standard A | Non-government-funded | Residential year-round<br>Residential seasonal<br>General Service single-phase<br>General Service three-phase |
| Street lighting | Community-owned public lighting | Street lighting |

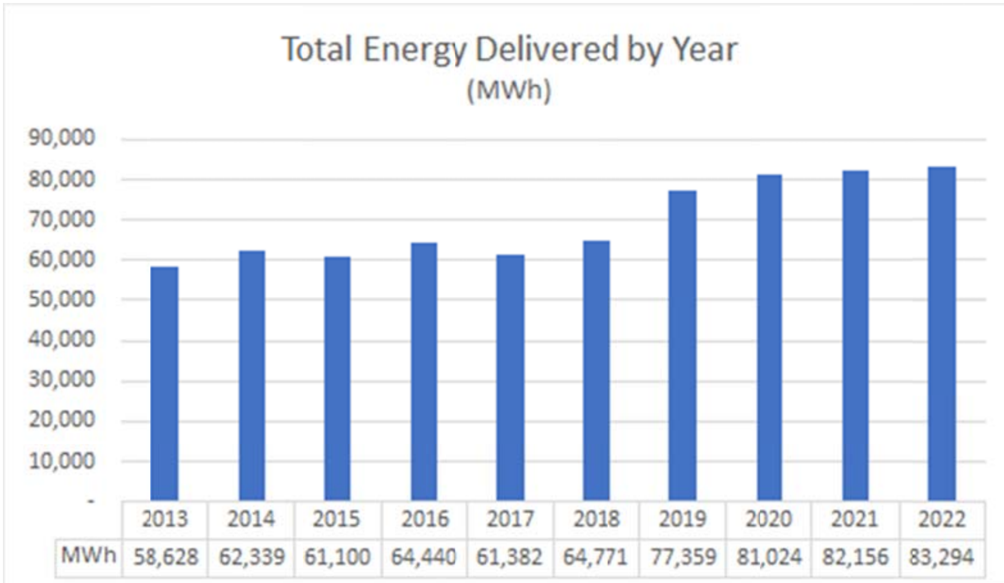
As depicted in Figure 1-5, the customer base has been stable over the historical period, but is expected to grow in the next five years with the addition of the three new communities. The largest step increase is projected for 2019 when Remotes begins serving Pikangikum.

Figure 1-5: Year-end (2013-2016) and Forecast (2017-2022) Customer Counts



The total annual amount of energy delivered remained generally consistent over the historical period, as shown in Figure 1-6, but is expected to increase over the forecast period as new communities are added.

Figure 1-6: Total Annual MWh Delivered




### 1.4.3 Electricity Generation

Remotes generates electricity to meet its obligations under Section 29 of the *Electricity Act, 1998,* since the communities it serves are not connected to Ontario's bulk electricity system. The main source of electricity supplied to the communities are 57 diesel-fuelled generators with a combined capacity of 31,000 kW. Remotes also owns wind turbine generators and hydroelectric generating facilities. There are wind turbines at four sites: three in Kasabonika with a capacity of 10 kW each, and one in Big Trout Lake with a capacity of 60 kW. There are two hydroelectric generating facilities in Deer Lake sized 225 kW each and one in Sultan with 150 kW capacity.

### 1.4.4 Energy Conservation and Demand Management

Remotes' energy Conservation and Demand Management ("**CDM**") program aims to reduce the kWh usage in the communities as a means of managing system costs and improving the affordability of electricity bills for the company's customers. To assist Remotes in the development and delivery of CDM programs the company entered into several partnerships with the participating First Nation communities, Northwest Company, Elephant Thoughts Energy Conservation Youth Camps, and MGM Electrical Commercial Lighting Retrofit Program. The scope, nature and impact of the resulting programs are discussed below. Remotes program is supplemented by programs aimed at First Nation communities managed by the Ontario Power Authority ("OPA") [now the Independent Electricity System Operator ("**IESO**")] and federal programs.

#### 1.4.4.1 Programs over the Historical Period

The following CDM programs were created and implemented over the past five years. Each program was promoted to customers by Remotes and through community representatives.

**Community Conservation Pilot Program**

Since 2006, Remotes offered an array of free products and financial support to the communities, enabling them to hire local Energy Conservation Officers to act as a key liaison, or community spokesperson, and installation support. The program was offered in partnership with local Band Councils and provided hands-on practical training as well as community information sessions. The program has been discontinued due to difficulty in engaging Band Councils as partners and in hiring, training, and retaining local resources to carry out the program.

**Mail in Rebate Program**

This program is application-based and presents a mail-back rebate on Energy Star and other energy efficient products when purchased.

**Energy Conservation Youth Camps**

The primary purpose of this CDM program was to engage community youth aged seven to twelve to learn about energy and water conservation. Camps were held over multiple days and delivered by an external provider responsible for developing a hands-on, age-appropriate curriculum. The program was delivered in four communities, with the delivery costs being shared with the participating communities. The program was discontinued due to limited community interest.

**Community Conservation Competitions**

This program created friendly competition among community members to drive a conscious effect to conserve electricity. Participants were eligible to win cash prizes for saving the most electricity based on their historic data. This program was implemented in one community over a few months. Although the participating community decreased its consumption by 12% during the competition, longer-term results were not sustained and the program is no longer offered.

**Commercial Lighting Retrofit**

Designed to assist commercial and Standard A customers reduce their energy consumption, this program assists customers with upgrades to their lighting systems. Remotes facilitates detailed lighting audits and upgrade cost estimations by a third-party company. Remotes does not have any industrial customers and has very few commercial and institutional customers, making the uptake of this program limited. Remotes continues to market this program.

**Holiday Lighting Exchange**

This program was offered on a community-by-community basis. The intent of this program was to switch out old incandescent holiday lighting with LED options. As lighting exchanges were offered in all the First Nation communities and have been completed by interested customers, opportunities for further deployment of holiday lights are limited.

**Rebate–Fridge Roundup**

This program was offered to all communities with Northern Stores in partnership with Northwest Company. The program offered free pickup and disposal of old refrigerators and a rebate if a participant purchased a new Energy Star refrigerator. Only two communities signed up, with only a handful of customers participating. Based on the limited uptake, the program is no longer marketed.

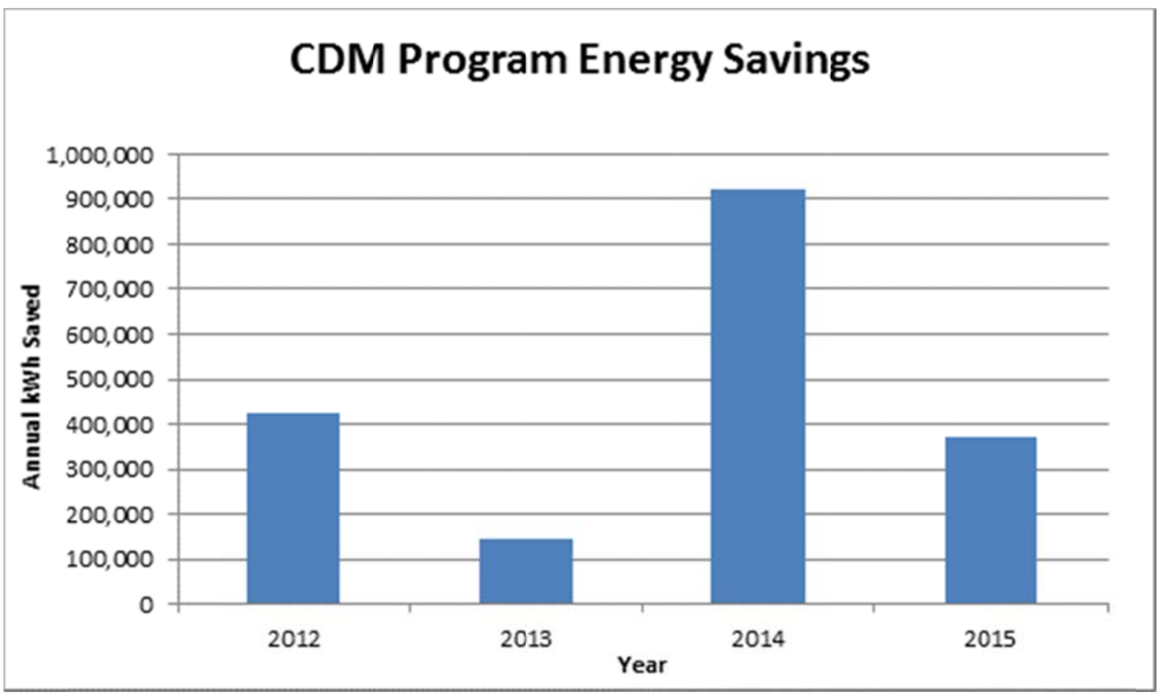
**Street Lighting Retrofit**

This program targets communities with existing streetlight systems and provides financial assistance to retrofit existing inefficient lamps to LED replacements. It is available to each of the seven communities with streetlight systems. To date, only one has taken advantage of the program. Remotes will continue making this program accessible for the remaining six communities until the upgrades are complete.

### 1.4.4.2 Achievements

Figure 1-7 depicts the combined energy savings of Remotes' CDM program for the years 2012 to 2015. The amount of kWh savings is directly related to the amount of participation at the community level and the amount of product installed.

Figure 1-7: CDM Program Energy Savings, 2012-2015




Externally-funded programs impacted program uptake over the historical period. Both the federal government and the IESO offered similar programs in the communities.

### 1.4.4.3 Challenges and Future Outlooks

There are numerous challenges affecting the execution of Remotes' CDM programs. First, the isolation of the communities means that there are limited opportunities to exchange large items such as refrigerators, since they must be transported out of the communities over winter roads. The OPA (now the IESO) and the federal government both offered communities opportunities to create community energy plans. From those plans, Band Councils expressed interest primarily in renewable energy development and in grid connection. In particular, renewable energy fits well with community priorities for environmental protection and as a means of creating local business opportunities. Interest from Band Councils on partnering in CDM initiatives was comparatively limited. Without strong support for the CDM programs from Band Councils, recruiting, training, and keeping local resources in place is challenging.

Remotes' customer base consists primarily of residential customers and lacks large commercial and industrial segments that provide material CDM program attainments for the rest of the province. Given the small number of customers and funding for similar programs from CDM, there are limited opportunities for savings.

Remotes is not included as part of the province-wide Conservation First Framework and, therefore, has not been allocated a budget or program achievement targets under the current framework.

Considering the above-noted factors, Remotes has allocated its resources in support of REG investments to better align itself with the preference of community leadership. Future CDM activities undertaken by Remotes will focus on community education and awareness, the kWh benefits of which cannot be readily attributed to specific measurable decreasing demand.

# 2 Distribution System Plan (5.2)

This section provides a high-level overview of the DSP including information on coordinated planning with third parties and performance measurement for continuous improvement.

## 2.1 Distribution System Plan Overview (5.2.1)

Remotes operates 19 isolated distribution systems in 21 communities in Northern Ontario. Remotes' service area will be expanding to include three additional communities. There are over 1,000 kilometres between the northernmost community, Fort Severn, and the southernmost community, Biscotasing. Thirteen of these communities are accessible by air only, meaning that Remotes' personnel, stationed in Thunder Bay, must fly to and from the communities when work is required. Given the extensive use of air transportation, cargo costs become an important consideration for the budget optimization efforts. The transportation of cargo is also an important planning consideration, as equipment and building materials cannot be purchased in the communities, can be too large to fly in regular cargo planes, and must therefore be trucked in over the six-week winter road season. If weather does not permit, winter roads may not be available to transport freight. Remotes keeps equipment and lodgings for its crews in each community to facilitate multiday project construction and maintenance activities and alleviate air transportation costs.

In the absence of a transmission system connection, Remotes is the generator and distributor for its customers. Cat Lake, anticipated to be added to Remotes' service area in 2018, is the only community connected to the transmission system. Much of the capital and system operations and maintenance ("**O&M**") expenditures is related to the upkeep and replacement of the diesel generator fleet. Remotes has a rigorous program to manage its generator fleet, including maintenance, overhauls, and replacements based on the number of operational hours ("**engine-hours**"). Diesel fuel is by far the single most significant cost for Remotes.

Planning for growth in Remotes' service territory is complex and somewhat unpredictable. Funding for growth-related capital is mainly a federal responsibility. INAC faces funding constraints and an overwhelming need for infrastructure in First Nations communities. The need for electricity infrastructure competes with requirements for schools, housing, water treatment plants, etc. The timing for funding approvals and the amount of funding available is uncertain and requires planning flexibility to accommodate growth within these communities. The federal government also has rules related to the timeframe in which the funding is spent and a project is completed. If funding is not spent within the federal government's time frame, the funding is returned to federal general revenues or deployed to another needed project. Consequently, funding levels and projects may be determined late in INAC's fiscal year and if funding becomes available, Remotes adjusts its planned work program to accommodate upgrade projects.

The provincial government plans to connect 16 remote communities to the transmission system. Nine of these communities are presently served by Remotes and seven are operated by Independent Power Authorities ("**IPA**s"). The provincial and federal governments have indicated that all the communities must be served by a licensed distribution company to connect to the grid. Five IPAs have requested service from

Remotes. Two of these IPA communities, Pikangikum and Wunnumin Lake, are planned to be included in Remotes' service territory over the forecast period. Although an Order-in-Council has been issued by the Minister of Energy, the Remote Community Connection Plan is still in draft form. Wataynikaneyap ("**Watay**") Power, the future owner and operator of the new transmission facilities, is commencing the development and approval process. An IESO-led study is considering the feasibility of leveraging Remotes' diesel generators for backup power supply once these communities are grid-connected.

In summary, these unique operating conditions are reflected in Remotes' DSP.

### 2.1.1 Key Elements of the DSP (5.2.1a)

To understand the key elements of Remotes' DSP, it is first important to understand the prospective business conditions driving the size and mix of capital investments required to achieve planning objectives over the forecast period. Capital investments are divided into three main categories of distribution, generation, and general plant. Each of these is discussed in a separate section below.

#### 2.1.1.1 Distribution

Table 2-1 presents the distribution capital expenditures and system O&M costs for both the historical and forecast period. In accordance with the OEB requirements, the distribution capital expenditures are separated into three investment categories of system access, system renewal, and system service – although Remotes made no system service investments over the historical period and plans no such investments over the forecast period. General plant investments are described separately in Section 2.1.1.3.

Table 2-1: Historical and Forecast Capital Expenditures and System O&M - Distribution

| Investment Category | Historical ($'000) | | | | | Forecast ($'000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **System Access** | | | | | | | | | | |
| Gross | 597 | 605 | 800 | 534 | 872 | 912 | 1,065 | 1,121 | 1,143 | 1,166 |
| Contributions & Removals | (474) | (574) | (757) | (464) | (872) | (912) | (1,065) | (1,121) | (1,143) | (1,166) |
| Net | 123 | 31 | 42 | 70 | - | - | - | - | - | - |
| **System Renewal** | | | | | | | | | | |
| Gross | 1,291 | 739 | 681 | 895 | 742 | 772 | 899 | 947 | 965 | 983 |
| Contributions & Removals | (535) | (235) | (137) | (135) | (241) | (250) | (290) | (304) | (311) | (313) |
| Net | 756 | 504 | 544 | 760 | 501 | 522 | 609 | 643 | 654 | 670 |
| **System Service** | | | | | | | | | | |
| Gross | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Capital** | | | | | | | | | | |
| Gross | **1,889** | **1,344** | **1,481** | **1,428** | **1,614** | **1,684** | **1,964** | **2,068** | **2,108** | **2,149** |
| Contributions & Removals | **(1,010)** | **(809)** | **(895)** | **(599)** | **(1,113)** | **(1,162)** | **(1,355)** | **(1,425)** | **(1,454)** | **(1,479)** |
| **Distribution Capital, Net** | **879** | **535** | **586** | **830** | **501** | **522** | **609** | **643** | **654** | **670** |
| **Distribution O&M** | **4,981** | **4,105** | **3,260** | **3,908** | **4,197** | **4,393** | **5,055** | **5,567** | **5,671** | **5,496** |
| **Total Spend, Distribution** | **5,860** | **4,640** | **3,846** | **4,738** | **4,698** | **4,915** | **5,664** | **6,210** | **6,325** | **6,166** |

#### 2.1.1.1.1 System Access

System access investments are a small portion of Remotes' spending over the forecast period. The size and mix of investments in this category are largely determined by customer requests and other external factors. The work is 100% recoverable from the requesting parties, and includes service cancellations, fixed price layouts, new customer connections, and service upgrades. Service cancellations are initiated by customers to ensure that monthly billing ceases. Most cancellations are a result of house fires or customer requests to disconnect services that are no longer needed. Fixed price layouts are provided when requested by customers in a cost-effective manner while ensuring compliance with Remotes' Distribution Standards as required under *O. Reg. 22/04*, the electrical distribution safety regulation under the *Electricity Act, 1998*. New customer connections and service upgrades are also driven by customers seeking connection to the system where sufficient capacity is available.

#### 2.1.1.1.2 System Renewal

A large portion of distribution capital investment in the system renewal category falls under Distribution System Improvements. Major distribution system capital improvements are made in one or two communities per year – depending on the size of the community – along with minor betterment projects in other communities. These betterments typically entail replacements of aging or defective poles, conductor restringing, and pole re-alignments based on the asset condition surveys in the community. Betterments and system upgrades are made to facilitate system reliability and joint-use of poles. New Viper switches are installed based on the power system reliability in the community, cold-load pickup, and operating experience. Viper switches allow on-site operator response as well as operating flexibility to limit the impact of lengthy outages to customers.

Other distribution system capital investment in the system renewal category includes Defective Meter Replacements, Minor Storm Damage Repair, Damage Claims, and Small External Demand Requests. Defective Meter Replacements and storm damage repairs mainly depend on severe weather occurrences, particularly lightning, wind, and ice storms. Damage claims work entails repairs to equipment resulting from damaged caused by members of the public.

Although the number of distribution assets under management by Remotes is expected to increase over the forecast period when the new communities are added to the service area, no major increase in distribution system renewal spending has been planned since INAC is funding upgrades to the distribution lines before they are transferred to Remotes. This will, however, affect the amount of O&M expenditures in the future to maintain this equipment. Increased metering costs have been budgeted based on the anticipated service area additions.

The planned increase in spending on these programs over the forecast period is modest.

#### 2.1.1.1.3 System Service

There are currently no system service programs budgeted on the distribution side.

### 2.1.1.2 Generation

Table 2-2 depicts the generation capital expenditures and system O&M costs for both the historical and forecast period. The generation capital investments are divided into the system renewal and system service categories. Generation investments do not fall into the system access category, since it entails distribution system work to connect work to connect customers, such as metering and service layouts. General plant investments are described separately in Section 2.1.1.3.

Table 2-2: Historical and Forecast Capital Expenditures and System O&M - Generation

| **Investment Category** | **Historical ($'000)** | | | | | **Forecast ($'000)** | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
| **System Renewal** | | | | | | | | | | |
| Gross | 3,651 | 4,064 | 1,172 | 2,659 | 1,795 | 1,788 | 2,847 | 3,582 | 3,994 | 2,426 |
| Contributions & Removals | (250) | (449) | 115 | (224) | (67) | (144) | (211) | (213) | (204) | (205) |
| Net | 3,401 | 3,615 | 1,288 | 2,434 | 1,728 | 1,644 | 2,636 | 3,369 | 3,791 | 2,221 |
| **System Service** | | | | | | | | | | |
| Gross | 499 | 167 | 7,054 | 2,588 | 7,884 | 5,853 | 6,852 | 6,392 | 5,412 | 5,810 |
| Contributions & Removals | (43) | (360) | (7,073) | (2,588) | (7,471) | (5,348) | (6,126) | (5,717) | (5,021) | (4,962) |
| Net | 456 | (193) | (19) | 0 | 413 | 505 | 726 | 675 | 391 | 848 |
| **Total** | | | | | | | | | | |
| Gross | **4,150** | **4,231** | **8,226** | **5,247** | **9,679** | **7,641** | **9,699** | **9,974** | **9,406** | **8,236** |
| Contributions & Removals | **(293)** | **(809)** | **(6,957)** | **(2,813)** | **(7,538)** | **(5,492)** | **(6,337)** | **(5,930)** | **(5,225)** | **(5,167)** |
| **Generation Capital, Net** | **3,857** | **3,422** | **1,269** | **2,434** | **2,141** | **2,149** | **3,362** | **4,044** | **4,182** | **3,069** |
| **Generation O&M** | **11,811** | **13,120** | **11,982** | **12,883** | **15,168** | **15,496** | **15,786** | **16,737** | **17,024** | **17,315** |
| **Total Spend, Generation** | **15,668** | **16,542** | **13,251** | **15,317** | **17,309** | **17,645** | **19,148** | **20,781** | **21,206** | **20,384** |

### 2.1.1.2.1 System Renewal

Generation system renewal spending for the management of Remotes' 57 generator units accounts for, on average, 60% of Remotes' budgeted net capital expenditures over the forecast period. Generation programs in the system renewal category are largely driven by condition of the units. The number of hours that an engine operates, not age, determines when a generator should be replaced or overhauled. Remotes performs this work in accordance with manufacturer's recommendations. Remotes also considers the maintenance history (reliability) of the unit, future capacity requirements and access to parts when making repair or replacement decisions. Generating station civil improvements are budgeted based the condition of the foundations and structures as determined through inspections. Day and bulk tank replacements are planned based on the need to replace end-of-life fuel tanks determined by condition and compliance.

### 2.1.1.2.2 System Service

Generation programs in the system service category make up a significant portion of Remotes' gross capital expenditures, but many of these projects are funded externally.

Generator upgrade projects are driven by capacity requirements and are 100% recoverable. SCADA and PLC programs are non-recoverable system service investments over the forecast period, which are driven by the requirement for improved plant data acquisition and control, generator asset management, and operator interaction through a modern Human-Machine Interface ("**HMI**").

#### 2.1.1.3 General Plant

General plant investments are modifications, replacements, or additions to Remotes' assets that are not part of its distribution or generation system. Individual programs in the general plant category over the forecast period fall below the materiality threshold ($283,000). These investments include life extension of staff housing in each community, driven by the condition of the lodging. Investments into storage buildings and other miscellaneous civil projects are made based on the need to have a suitable location that is large enough to store and perform maintenance on large equipment such as backhoes and Radial Boom Derricks ("**RBD**s"). This need is partly due to the transportation issues that exist in the Remotes. Other investments into minor fixed assets are made to purchase items such as storage containers and snow buckets.

Table 2-3: Historical and Forecast Capital Expenditures – General Plant

| Investment Category | Historical ($'000) | | | | | Forecast ($'000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **General Plant** | | | | | | | | | | |
| Gross | 691 | 677 | 473 | 914 | 1,085 | 565 | 572 | 581 | 590 | 598 |
| Contributions & Removals | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net** | **691** | **677** | **473** | **914** | **1,085** | **565** | **572** | **581** | **590** | **598** |

### 2.1.2 Anticipated Sources of Cost Savings (5.2.1b)

#### 2.1.2.1 Historical Achievements

Remotes has introduced many programs over the past few years to improve efficiency, contain current costs, and mitigate future cost increases. Through prudent planning and DSP execution. Remotes will continue to realize cost savings over the forecast period.

Table 2-4 illustrates the anticipated cost savings delivered through these programs.

1 Table 2-4: Summary of Cost Savings 2017-2022

| Cost Savings | Historical ($) | | | | Forecast ($) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Winter Road Fuel Savings | 1,144,998 | 3,516,961 | 1,170,388 | 496,576 | 570,783 | 570,783 | 570,783 | 570,783 | 570,783 | 570,783 |
| First Nation Fuel Savings | 407,642 | 347,572 | 177,023 | 658,264 | 643,151 | 643,151 | 643,151 | 643,151 | 643,151 | 643,151 |
| Meter Reader Savings | 758,819 | 873,007 | 952,415 | 1,370,443 | 1,370,857 | 1,374,653 | 1,379,422 | 1,384,341 | 1,388,536 | 1,393,624 |
| Operator Savings | 6,825,617 | 9,797,954 | 9,727,773 | 9,825,312 | 9,825,312 | 9,790,318 | 9,861,849 | 9,934,095 | 9,971,020 | 10,044,718 |
| Webshare Savings | - | - | 79,200 | 79,200 | 79,200 | 79,200 | 79,200 | 79,200 | 79,200 | 79,200 |
| **Total** | **9,137,076** | **14,535,494** | **12,106,799** | **12,429,796** | **12,489,304** | **12,458,105** | **12,534,405** | **12,611,571** | **12,652,690** | **12,731,477** |

2

Diesel fuel is Remotes' single largest cost component. Winter road fuel savings is the cost difference between trucking fuel in over winter roads compared to flying it in. Similarly, First Nation fuel savings is the cost difference between trucking fuel in over winter roads and storing it in First Nation tank farms compared to flying it in.

Meter reading and operator savings are differences in cost between contracting with a local person in the community and using workforce resources from Remotes. Usually, Remotes reads its own meters but contacts the First Nation band councils for local employment. Contracting with local resources offers job opportunities within economically disadvantaged communities.

Webshare savings result from accessing data such as 3D scans via Webshare instead of flying to the site for tasks such as preliminary design updates. The estimated value also includes productivity gains from a reduction in the time required to gather accurate information such as nameplate data.

In addition to these sources of cost savings that have been described and estimated over the forecast period, Remotes engages in numerous initiatives to reduce costs that are less readily quantifiable.

As the condition of diesel generators deteriorate, they become less fuel-efficient and, therefore, costlier to operate. Capital investments to replace or overhaul generators mitigate the loss of efficiency thereby reducing the fuel costs to operate the generator. Generator upgrades, although driven by capacity constraints, have the added efficiency cost benefit of replacing an older generator. Due to the continuous improvement of generator technology, new diesel generators installed in the field have higher nameplate efficiency than the older models they replace, amplifying the fuel savings. Remotes uses automatic generator dispatch to optimize the efficiency of its fuel consumption. Planned replacements, overhauls, and upgrades reduce the risk cost associated with owning and operating the generator.

Good project scheduling, planning and execution contribute to cost savings in terms of avoided costs. This includes project scoping to bundle assets into a single project for optimization of resource mobilization and demobilization. This approach reduces the cost of air transportation of personnel and also ensures crews perform all known work required when they visit a remote community.

Planned replacements of distribution assets through the Distribution System Improvements program are a cost-effective way to manage these assets. The betterment of one community per year is planned to focus Remotes' efforts and reduce the number of flights. This program focuses on the worst sections of feeders identified during inspections. This proactive work reduces future trouble call costs increasing the system's resiliency to storms through pole replacements, conductor restringing, and pole realignments.

SCADA and PLC upgrades planned over the forecast period will result in improved system data acquisition and control with an HMI at several generating stations. The improved SCADA system will reduce the number of trips required for troubleshooting when the alarm can be cleared remotely. The new HMI will reduce the operator response time though improved interaction and alarm handling. The data collected by these new systems are expected to be used to drive asset management decisions in the future and to better monitor the condition of the diesel generator fleet.

As part of the generator replacements and upgrades, old generators are brought back from the site and sent out for investment recovery. Removed generators can be used as spares or for spare parts to derive the most value out of the retired asset.

Generator upgrade projects factor in the available transformation capacity of the Generator Step-Up transformers ("**GSU**s"). If the existing GSU can provide adequate supply for the community and is in serviceable condition, it remains in service. This serves to reduce the capital cost requirement of the project.

New generating station construction incorporates the *Remotes Station Design Guidelines*. By following standardized designs, Remotes reduces the design, engineering, and construction costs of these projects. Since these projects do not affect the rate base, these cost savings are passed on directly to INAC. Furthermore, the use of standardized generating station designs allows Remotes' crews to follow existing work practices and manuals for the upkeep of the stations, improving operational efficiency.

New connections and fixed price layouts are planned using standardized designs that meet the requirements of *O. Reg. 22/04*. This decreases the engineering and design costs of projects, while still providing high-quality layouts. Since these programs are customer-funded, these cost savings are passed directly to customers.

Additional cost savings are achieved through the sharing of software and IT systems with Remotes' parent company, Hydro One Inc. The cost sharing is defined in Service Level Agreements between Remotes and Hydro One Inc.

#### 2.1.2.2 Investments in Efficiency

Over the past five years, Remotes has invested in civil improvements such as walkways and garages to reduce time that crews spend shovelling snow on sites, digging out hydro trucks from heavy snow, reducing the time to respond to emergencies, and/or commencing work in the station. Investments in RBDs have improved crews' ability to perform line work in the communities. However, the distance and time required to get to and from site makes these efficiency improvements difficult to quantify. Remotes has focussed on improvements to its procurement planning to ensure that materials can be transported to site over winter road and jobs executed when planned. With this DSP, Remotes is investing in the building blocks necessary to modernize an off-grid electricity system. Besides maintaining the fuel efficiency from the original PLC-SCADA system, the new SCADA system is expected to improve Remotes' ability to diagnose the cause of failures from the Thunder Bay office. Along with the improved 3-D drawings of the plant, this will help to ensure that field staff have the materials required to fix the failure when they get to site. It may also reduce the time required for field staff to troubleshoot on site, or improve the ability for operators to respond to outages. Other Ontario utilities have uncovered ways to use improved data from their assets to reduce trouble costs, and Remotes expects to leverage modern communication systems to create similar impacts on its business.

Remotes has experience with the impact of high penetration hydro-electric power in Sultan, where the renewable resource can fully power the community during the summer months reducing engine hours and required engine maintenance. Solar power is a new technology in a Canadian off-grid where limited solar resource, small scale, expensive installation costs and distribution system penetration have delayed implementation. This is the technology supported by the federal and provincial governments. Solar-battery installations may have an impact on winter peak, but is more a more promising technology for the potential to reduce engine hours during the summer months. With limited operational experience with this technology, Remotes is not yet able to estimate the impact on engine hours, but the potential is there for the two planned solar projects in Fort Severn and Gull Bay.

By participating in, and advocating for the Watay project, Remotes is working toward a large fuel cost reduction, much lower emissions and reduced capital and OM&A expenditures on diesel plants, and a more flexible power solution for its customers.

### 2.1.3 Period Covered by DSP (5.2.1c)

This DSP covers a historical period of 2013 to 2016, 2017 is the Bridge Year. The forecast period is 2018 to 2022, where 2018 is the forward Test Year.

### 2.1.4 Vintage of the Information (5.2.1d)

The information contained within this DSP should be considered “current” as of January 2, 2017.

### 2.1.5 Important Changes to Asset Management Processes (5.2.1e)

This is Remotes’ first DSP filing; therefore, there are no changes to its asset management process compared to a previous DSP filing. Remotes’ previous Cost of Service filing did not include an Asset Management Plan.

### 2.1.6 DSP Contingencies (5.2.1f)

The execution of Remotes’ investment programs is contingent upon various external factors. The most important of these factors are external funding requirements (through INAC), nature and volume of customer-initiated work, transportation requirements, resource availability, and regional electricity infrastructure requirements.

**External Funding Considerations**

INAC provides funding for programs, services and initiatives to First Nation, Inuit and Northern communities, governments and individuals, as well as to Aboriginal and Métis organizations. Under the terms of the electrification agreements, INAC is responsible for funding generation and distribution capital upgrades associated with load growth in First Nation communities served by Remotes. When a generation upgrade project is needed to provide additional capacity, Remotes works closely with the First Nation community through the funding and approval process. The First Nation community has the final say in the technical design of the project based on the feasible options outline by Remotes, which is usually the most cost effective option. Since this type of project must be customer-initiated, the year of execution depends on the First Nation community meeting all the requirements before starting the project and on the availability of INAC funding. Remotes mitigates this risk through its strong community outreach program and involvement of the First Nation representatives early in the planning process. Due to federal funding constraints and competing priorities for INAC capital, the available INAC funding is insufficient to finance required station upgrades in the communities; however, this issue was partially resolved in 2013 following extensive engagements with INAC. The resulting capital funding allocations commencing in 2014 relieved connection constraints in some of the communities. While Remotes is confident in the ability of the communities to secure funding planned incremental capacity upgrade projects based on strong relationship with INAC, it notes that external factors outside of its control always present certain risks. For instance, INAC operates on a fixed annual capital budget that covers all capital needs within communities, not just electricity, meaning that funding availability can be affected by emergency funding requirements in the IPAs communities, for other capital requirements or by centrally determined Federal Government's funding priorities.

**Customer-Initiated Projects**

The year-to-year changes in scope, nature, and volume of customer-initiated projects all affect Remotes' pace and prioritization of work execution activities. Customer-initiated projects include metering, service cancellations, damage claims, small external demand requests, fixed price layouts, new customer connections, and service upgrades. The level of expenditures required for these activities fluctuates between years based on the volume of work requested by customers. However, these fluctuations do not affect the rate base, since this work is 100% recoverable from the requesting customers.

**Transportation Challenges**

Transportation is the third major contingency affecting Remotes' project execution. Many of the First Nation communities are not accessible by year-round roads. While personnel can be flown to and from the communities, large assets such as generators and GSUs must be transported by land. To do this, the environmental conditions must be favourable to allow for safe transportation of heavy equipment along winter roads. An entire year can pass without a winter road to a community becoming available, in which case the project is typically deferred. Remotes has the option of hiring a specialized transport plane to deliver the heavy equipment when there is no winter road available, but the cost is not usually justifiable. Remotes accepts the risk posed by winter roads to its project execution as a part of its unique operating conditions and modifies its capital plans when required.

**Resource Availability**

There is a lack of skilled trades contract resources living in the communities, and there are very few contractors who work in them. Remotes employs regular and casual staff, apprentices, and contract staff to complete capital and maintenance work. Work in the communities requires a number of different skilled trades including line maintainers, distribution technicians, environmental technicians, mechanics, electricians, and carpenters who specialize in distribution system upkeep, generator upkeep, and civil construction. Remotes also uses specialized resources for tasks such as vehicle servicing hydroelectric maintenance, and SCADA/PLC upgrades. Internal resource deployment is prioritized based on the urgency of the work required. Remotes' overarching priority is to keep its generators running to keep the lights on in the communities. Depending on the scope and nature of unplanned work that arises from time to time, planned investments may be deferred if resources are unavailable. For instance, if there is an unplanned engine failure, resources can be pulled from capital jobs to perform maintenance work to keep the power on. To mitigate this risk, Remotes focuses on planned maintenance and capital upgrade work to reduce the amount of unplanned work that can stretch resource availability. Examples of planned projects and programs include distribution system improvements, generator overhauls, and generator replacements.

**Regional Electricity Infrastructure Requirements**

Remotes is a participant in the Regional Planning Process for the North of Dryden region, which is part of the Northwest Ontario Planning Region and covers the Remote Community Connection Plan. The 2014 draft Remote Community Connection Plan is a business case which informed a July 29, 2016, Order-in-Council from the Provincial Government. The Order confirms the need for the project to connect 16 remote communities to the transmission system. Nine of these communities are presently served by Remotes. The provincial and federal governments have indicated that communities must be served by licenced distributors to qualify for grid connection. Five of the communities now served by IPAs have now requested service from Remotes. Remotes expects to take over service of two of these communities within the next five years. The potential construction of a transmission line to the communities currently served by Remotes is not expected to affect the investments in the communities over the five-year period comprising this DSP, as the transmission construction activities are anticipated in the medium- to longer-term. As the transmission connection plans mature and firm up, Remotes will review its investment plans for the appropriate timeframes and make any amendments that may be warranted based on discussions with other parties involved.

**Other Contingencies**

Other contingencies that may affect the size and mix of capital investments over the forecast period include inclement weather, joint-use requests, and investments into minor fixed assets. While inclement weather can delay projects, it generally does not lead to project deferral; rather inclement weather is an investment driver for repairs to the distribution system due to ice, wind, and storms. Joint-use pole requests are included as part of the Distribution System Improvements program and are contingent on external requests by third parties such as Bell or the local First Nation. Planned work requirements include pole replacements and reframing to accommodate telecommunication lines on the poles. Customers benefit from the efficiencies realized due to joint-use of assets. Forty per cent of the cost of joint-use projects are funded by external parties. Investments into minor fixed assets are budgeted based on the expected needs each year, but the actual investments are driven by specific needs that occur within the year.

## 2.2 Coordinated Planning with Third Parties (5.2.2)

### 2.2.1 Records of Engagement (5.2.2a)

Remotes regularly engages its customers and leaders of the First Nation communities it serves, federal government agencies such as INAC, provincial government bodies such as the OEB and the Ministry of Energy, the IESO, and other electricity distributors and transmitters.

### 2.2.1.1 Customer Engagement

#### 2.2.1.1.1 Customer Advisory Board Meeting

On June 23, 2016, Remotes held its annual Customer Advisory Board meeting.

**Purpose of the Engagement:**

The annual Customer Advisory Board meeting facilitates feedback from the Customer Advisory Board on several topics such as updates to the Ontario Electricity Support Program, priority setting, and REG investments.

**Engagement Initiation:**

Remotes initiated the engagement.

**Other Participants in the Engagement:**

Other participants in the engagement are members of the Customer Advisory Board. The Customer Advisory Board includes commercial and residential customers in representing communities serviced by Remotes. Customers apply to be members of the Board and Remotes' management chooses representatives based on these applications. Customers must live or work in Remotes' service territory, be willing to attend meetings, and be willing to offer constructive advice about Remotes' services.

**Final Deliverables**

Members of the Customer Advisory Board voted to indicate their opinion regarding the prioritization of the company's key focus areas. The resulting relative priority allocation is shown in Table 2-5.

Table 2-5: Priorities Ranked by Customer Advisory Board

| Work Program Component | Relative Customer Priority |
|---|---|
| Affordability | 37.8% |
| Renewable energy | 24.3% |
| Load growth | 16.2% |
| Reliability | 10.8% |
| Customer service | 8.1% |
| Environmental protection | 2.7% |

**Effect on the DSP**

When setting its priorities for planning and ranking projects, Remotes took into consideration the priorities of its Customer Advisory Board outlined in Table 2-5. More information regarding the impact of this prioritization on the company's planning can be found in Section 4.2.

### 2.2.1.1.2 Customer Workshop

On November 23 and 24, 2016, Remotes jointly hosted a workshop with the Opiikapawin Services Limited Partnership, a partnership of the First Nation communities who are the majority owners of on the Watay project. Community representatives from nine of the communities Remotes serves were invited to attend the workshop. The community representatives each included a member the Band Council, a member of the Watay Board of Directors, and the community Remote Electrification Readiness Program worker (a community member who has been hired in the community to work on community readiness for connection to the grid). Representatives from INAC and OEB staff also attended this workshop.

**Purpose of the Engagement:**

The customer workshop provided an open discussion to plan for grid connection. The workshop also discussed Remotes' services, determined the preferences/priorities of the customers attending the workshop, and assisted OEB staff in carrying out their engagement with First Nation communities to determine First Nation Energy rates.

**Engagement Initiation:**

Together with the Tribal Councils, Remotes initiated the workshop.

**Other Participants in the Engagement:**

Other participants in the workshop included OEB staff, INAC, and the following First Nation communities:

- Bearskin Lake
- Big Trout Lake
- Kasabonika Lake
- Kingfisher Lake
- Sachigo Lake
- Wapekeka
- Weagamow Lake

Representatives from Sandy Lake and Deer Lake planned to attend, but weather restricted their travel.

**Final Deliverables**

The workshop provided recommendations in eight areas:

1. Backup generation: Remotes, INAC, and the First Nations will continue to work together to establish a backup generation plan for all the communities that are involved in the Watay project. Remotes will assess its own generation assets and will, on request from INAC and the local IPA community, assess the existing generation in the IPA communities. Further, each First Nation community representative will evaluate which individual buildings have backup generators installed (see Section 2.2.1.3.4 for more details). Any new construction of essential service infrastructure needs to include backup generation (school, clinic, water plant, sewage, etc.).

2. Environmental stewardship: Remotes and the First Nations will develop an environmental plan including annual reporting (see Section 2.3.4.2 on performance measures).

3. Affordability and rates: Participants expressed support for OEB staff's recommendations to make electricity more affordable for First Nation customers.

4. Customer Service: community representatives noted that most communications are with Band Councils and that Remotes should interact directly with community members. They expressed the desire for Remotes to hire a designated liaison in the First Nations who could engage directly with the community, improve accessibility to support programs (OESP and LEAP), and to improve disconnection communication with customers.

5. Priority setting: First Nation participants voted on a list of priorities for Remotes, indicating which aspects are most important to Remotes' customers.

Table 2-6: Priorities Ranked by First Nation Communities

| Work Program Component | Relative Customer Priority |
|---|---|
| Environmental protection | 21.5% |
| Community relations | 14.9% |
| Renewable energy | 14.9% |
| Customer service | 14.0% |
| Affordability | 14.0% |
| Reliability | 11.6% |
| Safety | 9.1% |

6. Housing connections: Remotes should attend housing and public works conferences to improve understanding and communication between First Nations and Remotes on housing construction and permits.

7. Safety and emergency response: Remotes should provide information in electrical safety at regional conferences.

8. Community relations: Remotes should develop a Community Relations and Engagement Policy that includes Remotes and First Nation roles and responsibilities.

9. Access to conservation and renewable programs: Remotes should increase customer engagement when designing CDM and REG participation programs so that they are accessible, meaningful, and used.

The detailed summary of this workshop can be found in Appendix E: 2016 Customer Workshop.

**Effect on the DSP**

Based on this workshop and on discussions with Band Councils, Remotes has worked closely with First Nations and other parties on several renewable energy studies, which are discussed in further detail in Section 2.2.1.4.

When setting its priorities for planning and ranking projects, Remotes took into consideration the priorities of its customers outlined in Table 2-6. Environmental stewardship is consistently identified as paramount to the First Nation communities and is accounted in all stages of project planning, ranking, engineering, and design. More information about these priorities can be found in Section 4.2.1. Remotes has also identified several measures related to environmental stewardship that it tracks. These measures are listed in Section 2.3.4.

Remotes is registered to the rigorous ISO 14001 standard and aims for continuous improvements in all aspects of environmental management.

Specific investments have been planned over the forecast period with environmental protection in mind. Day and bulk fuel tank replacements are planned over the forecast period to ensure compliance with the latest codes and reduce the risk of a fuel leak. New diesel generator replacements and upgrades are much more efficient than older generators and offer better structural integrity, resulting in lower emissions and reduced risk of ground contamination through leaks. Distribution System Improvements include replacement of distribution transformers exhibiting signs of leaking oil or other defects. Storage building projects in the general plant category include construction of proper facilities for vehicle storage and maintenance that reduce the environmental risk of these activities. Remotes is also working with customers to deploy customer-owned renewable technologies.

Joint infrastructure planning between Remotes and the First Nation communities is a continuous process. Remotes attends housing and public works conferences to improve its understanding of the communities' concerns and priorities, and provide information regarding its own plans, risks, or constraints as may be relevant. These meetings also drive the budgetary process for new customer connections, service upgrades, and fixed price layouts. In respect to the costs of these services, Remotes endeavours to reduce its costs through the methods listed in Section 2.1.2, such as using standardized designs that are compliant with *Ontario Regulation 22/04*. Remotes has also created opportunities for the connection of customer-owned renewable generation, with 15 projects currently in service.

### 2.2.1.2

Remotes operates in First Nation communities under funding agreements negotiated with INAC. Remotes and INAC representatives meet annually as a part of the ongoing planning program. Remotes also engages INAC regularly on the matter concerning the execution of specific projects and community outreach initiatives.

**Purpose of Engagements:**

The purpose of these engagements is to review the available generation capacity based on the historical and projected peak loads in the communities to forecast and plan necessary generation capital projects in the communities. Collaboration with INAC reduces costs and the overall risk related to power supply in the remote communities.

**Engagement Initiation:**

Remotes typically initiates the engagements.

**Other Participants in the Engagement:**

Other participants in the engagements typically include INAC's capital management staff and the assigned First Nation project management team.

**Final Deliverables**

Generation capital project meetings are held to initiate specific INAC-funded projects and to monitor project process. Once a project funding is initiated, Remotes participates and generally facilitates regular meetings. The meetings are held throughout the project to determine acceptable designs, timelines, and project progress. These meetings are held to meet the needs of the First Nation project management team and INAC capital management staff.

**Effect on the DSP**

Engagement with INAC is critical to the development and successful execution of generation upgrade projects listed in the system service category, given INAC's responsibility for capital project funding. Remotes and INAC have jointly identified the need to invest in Wapekeka, Fort Severn, Sandy Lake, Weagamow, and one of either Deer Lake or Kasabonika (to be re-evaluated over the forecast period) based on the available capacity and forecast load growth. These projects are entirely funded by the First Nation communities who, in turn, must apply for the funding from INAC. Remotes works closely with INAC to ensure the proper funding is in place for these projects to proceed.

INAC's role in the ultimate execution of the projects over the planned timelines is critical. In 2011, INAC experienced material funding constraints, rendering it unable to fund upgrades. As communities (and their load requirements) continued to grow, Remotes found itself in situations where it was unable to connect new electrical services. Remotes considered replacing engines with larger engines, but the cost to replace auxiliary systems was more expensive than funding a simple engine replacement, making these short-term solutions incompatible with the company's budgetary considerations and focus on efficiency. Following this experience, Remotes worked with INAC to modify the upgrade process so that smaller projects could be put in service quickly should a similar situation occur in the future.

#### 2.2.1.3 Transmission Connection Engagement

Remotes participates in all aspects of the engagements related to the connection of several northern communities to the bulk transmission system. The key engagements are related to transmission connection planning, transmission connection funding, regulatory support for IPAs, and diesel generation backup.

### 2.2.1.3.1 Transmission Connection Planning

**Purpose of the Engagement:**

The purpose of this engagement is to plan a transmission line that, if built, would connect several First Nation communities currently served by Remotes, along with several IPAs, thus expanding the service territory of Remotes.

**Engagement Initiation:**

The IESO initiated the engagement.

**Other Participants in the Engagement:**

Other participants in the engagement were the IESO, First Nations representatives, and representatives from federal and provincial governments.

**Final Deliverables**

During 2013 and 2014, as part of this planning process, the IESO asked Remotes to provide information to support this planning process. Information provided included historical load in the communities, historical peak load information, and aggregated information historical diesel usage and costs. At the IESO's invitation, Remotes also has attended three broad stakeholder meetings where the IESO discussed future transmission plans in the northwest. Although no new stations are currently planned, a transmission connection date should eventually be provided.

**Effect on the DSP**

While the anticipated timeline of the transmission line construction falls outside the forecast period of the DSP, this project will affect Remotes' planning considerations over the medium-to-long term. In the interim period, Remotes continues to be required to offer reliable electricity service in the communities, and enable the load growth through capital upgrades funded by INAC. Remotes anticipates maintenance of the diesel generation assets until the day the transmission connection work is completed and a diesel backup study determines the optimal path forward. However, in recognition of this eventuality and as a means of managing its budget, Remotes reduced its funding requests for this interim period and has recommended customers to downsize their requests from INAC. An example of a project deferred in this manner, is the foregone Weagamow tank storage upgrade driven by the anticipated connection.

The revised upgrade process now allows for station modifications to allow customers to connect to the system. Remotes is also exploring innovative approaches to increase capacity such as the tie-line between Wapekeka and Big Trout Lake and the connection of customer-owned renewable energy in Fort Severn.

### 2.2.1.3.2 Transmission Connection Funding

**Purpose of the Engagement:**

The purpose of this engagement is to develop a funding agreement for the transmission connection project.

**Engagement Initiation:**

Watay Power initiated the engagement.

**Other Participants in the Engagement:**

Other participants in the engagement were Watay Power and representatives from federal and provincial governments.

**Final Deliverables**

Watay Power is the transmission company that was identified as the future owner-operator of the transmission line to be constructed. Watay Power is owned by 22 First Nations in the north in partnership with Fortis Ontario. The provincial government designated this project in July 2016. The letter from the Minister of Energy is attached as Appendix C: Order-in-Council from the Minister of Energy.

The Order-in-Council identified 16 communities to be connected to the bulk electricity grid at an undetermined date. Nine of these communities are presently served by Remotes, namely:

- Sandy Lake
- Deer Lake
- Kingfisher Lake
- Kasabonika
- Wapekeka
- Kitchenuhmaykoosib Inninuwug (Big Trout Lake)
- Bearskin Lake
- Sachigo Lake
- North Caribou Lake (Weagamow)

In addition, two communities identified in the Order-in-Council are expected to join Remotes' service area over the historical period, namely:

- Wunnumin
- Pikangikum

**Effect on the DSP**

This consultation has allowed Remotes to also explore innovative approaches to increase capacity such as the tie line between Wapekeka and Big Trout Lake. The new distribution line will be necessary once the transmission line reaches the communities; therefore, the incremental cost of building the line earlier than required is much less than the cost avoidance of a larger station upgrade in the communities.

#### 2.2.1.3.3 Regulatory Support for IPAs

**Purpose of the Engagement:**

The purpose of these engagements is to educate communities served by Remotes and other First Nations operating IPAs on the provincial regulations related to electricity generation, transmission, and distribution.

**Engagement Initiation:**

The IESO and Watay Power initiated the engagements.

**Other Participants in the Engagement:**

Other participants in the engagement were the ESA, Watay Power, INAC, Ministry of Energy staff, and First Nation representatives.

**Final Deliverables**

As part of this effort, Remotes met with Chief, Council, and IPA representatives from North Spirit Lake, Wunnumin Lake, Muskrat Dam, Wawakapewin, Pikangikum, Poplar Hill, and Keewaywin. Information shared included ESA requirements, Ontario regulations, OEB programs, and rate setting. To ensure that distribution and generation assets meet provincial standards in the IPA communities, Remotes staff agreed to work with the ESA to inspect the assets in the communities and to identify defects that must be fixed ahead of grid connection. Inspections to date have taken place in Pikangikum, North Spirit Lake, and Wunnumin Lake. Reports are provided to the Tribal Councils and the local First Nations.

**Effect on the DSP**

Activities related to these engagements fall under the non-system O&M category and are not the focus of the DSP. The implementation of these activities will facilitate the successful connection of IPAs to the bulk electricity grid as part of the transmission connection project expected to take place in the medium-to-long term (outside of the planning period of the DSP).

Remotes has performed a considerable amount of work to help the northern IPAs prepare for anticipated grid connection. Based on the proposed transmission line route, the IPAs would be connected before any the communities served by Remotes are connected. The proposed line crosses the traditional lands of these communities, making their participation (and ultimate connection) a critical factor in the project's viability.

#### 2.2.1.3.4 Diesel Backup Study

**Purpose of the Engagement:**

This is an ongoing engagement to assess the feasibility of using diesel generators as a backup power supply to reduce the outage times for remote communities to be served by a new radial transmission line.

**Engagement Initiation:**

The IESO initiated the engagement.

**Other Participants in the Engagement:**

Other participants in the engagement are the IESO, INAC, Watay Power, Tribal Councils, and Ministry of Energy staff.

**Final Deliverables**

The diesel backup study is exploring the development of technology options, regulatory considerations, current and future financial responsibilities, and environmental considerations. A draft study has been prepared for review by all parties involved. Additional community engagement is required before the report is finalized.

**Effect on the DSP**

The likeliest timeline of the transmission line construction falls outside of the forecast period of the DSP. This engagement has not had any commensurate effect on the DSP, but will affect Remotes over the medium-to-long term. The results of the study will determine Remotes' role in the implementation and operation.

### 2.2.1.4 Renewable Energy Studies

**Purpose of the Engagement:**

The Ministry of Energy tasked the IESO with identifying options for renewable energy in the three First Nation communities served by Remotes that the IESO has determined as not economic to connect to the grid (Whitesand, Fort Severn, and Gull Bay).

**Engagement Initiation:**

The Ministry of Energy initiated the engagement, which is being led by the IESO.

**Other Participants in the Engagement:**

Other participants in the engagement are the Ministry of Energy, INAC, and community representatives.

**Final Deliverables**

Remotes met with the IESO, the Ontario Ministry of Energy, and INAC to discuss its Renewable Energy Innovation Diesel Emission Reduction ("**REINDEER**") program and opportunities to expand renewable energy and renewable microgrid projects across the off-grid communities. To date, Remotes has completed a Connection Impact Assessment for a biomass project in Whitesand and has assisted the First Nation and the IESO with technical design aspects of the proposed project. Engagements are also underway for a solar/battery project in Gull Bay and a solar project being constructed in Fort Severn.

**Effect on the DSP**

For all three renewable projects under development, Remotes has a distinct role. First and foremost, Remotes must ensure safe and reliable power to its customers. As such, Remotes is taking an active role in design and technical review of project plans, with integration into existing systems as the core focus given all projects noted are in the initial development stage.

If developed as planned, the biomass generation project in Whitesand is expected to produce electrical output that would displace electrical load within the community and that settlement would be based on the avoided cost of diesel fuel in that community. No firm project timeline has yet been established for this project, although construction is planned to begin in 2025.

A solar generation project, supported by federal and provincial grants, is currently being developed by Fort Severn First Nation and private sector developers. Remotes' role in this project is to ensure the ongoing reliability and stability of the existing microgrid and to ensure that the project can be integrated into the existing generation system. The project is staged, with 40 kW of net-metered solar installed to date. When fully installed, the project will qualify for Remotes' REINDEER program and, consistent with that program, Remotes will pay for the electricity produced based on the avoided cost of diesel fuel.

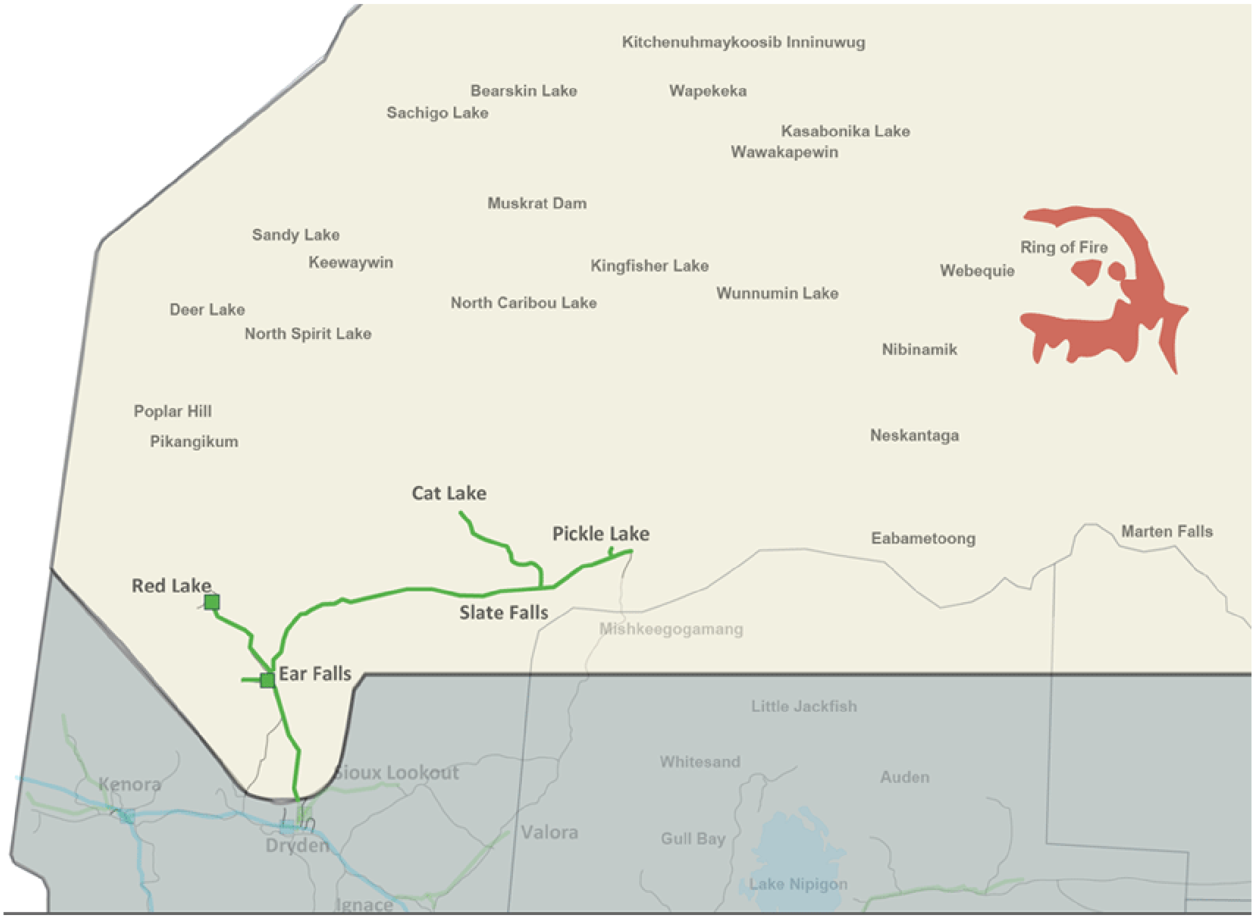
A high penetration solar/battery microgrid project, supported by provincial grants, is also planned for Gull Bay. The project is currently in the very early stages. It is anticipated that the project will also qualify for Remotes' REINDEER program and that settlement will also be based on the avoided cost of diesel fuel in that community.

In terms of generator upgrades and replacements, the three planned sites are not expecting upgrades over the forecast period. The upgrades will, however, affect future capacity.

### 2.2.2 Regional Planning Process (5.2.2b)

Remotes is part of the "North of Dryden" group for the Regional Planning Process. The North of Dryden area extends northward from Dryden to the towns of Ear Falls, Red Lake, Pickle Lake, and surrounding areas depicted in Figure 2-1. Electricity to the sub-region is currently supplied by the 115 kV Hydro One Networks Inc. transmission system. An Integrated Regional Resource Plan ("**IRRP**") was developed to identify the near-term and medium- to long-term electricity supply needs of the area and assess options that are available to address the needs in a timely, reliable, and cost-effective manner. Municipalities and First Nation communities were engaged in the development of the IRRP.

Figure 2-1: North of Dryden Area




The IRRP was published by the IESO on January 27, 2015. Drivers for increased electricity demand in the areas surrounding Red Lake, Pickle Lake, and the Ring of Fire include connecting 21 remote First Nation communities and growth in the mining sector. The IRRP recommended that a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake should be constructed along with upgrades to existing lines between Dryden and Red Lake for immediate implementation to address near- and medium-term needs for the Pickle Lake and Red Lake areas. The IRRP is included as Appendix B: North of Dryden IRRP.

The OPA (now the IESO) and the representatives of the remote First Nation communities and tribal councils in the area drafted the 2012 Technical Report for the Connection of Remote First Nation Communities in Northwest Ontario. Since the release of the plan in 2012, engagement of the communities has continued and an updated draft Remote Community Connection Plan was posted in August 2014. The updated analysis identifies that there is an economic case to connect up to 21 remote communities at this time, including the Marten Falls First Nation. The remaining communities are not economic to connect at present, largely due to their relatively small size and distance from existing transmission infrastructure.

The 2014 draft Remote Community Connection Plan is a business case which informed a July 29, 2016, Order-in-Council from the provincial government. This order confirms the need for the project to connect 16 remote communities to the transmission system. Nine of these communities are presently served by Remotes and two are expected to be served by Remotes in the future. While this will not affect investments in the communities over the five-year period of this DSP, it is expected that the construction activities of this new transmission line will affect Remotes planning considerations over the medium-to-long term. The order from the Minister of Energy is included as Appendix C: Order-in-Council from the Minister of Energy.

### 2.2.3 IESO Comment Letter (5.2.2c)

A request for a letter of comment was sent to the IESO on March 3, 2017. The OEB expects the letter to include the following:

- the applications it has received from renewable generators through the Feed-in Tariff ("**FIT**") program for connection in the distributor's service area;
- whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments;
- and whether the REG investments proposed in the DSP are consistent with any Regional Infrastructure Plan.

In regards to those points, Remotes noted that:

- Remotes' service area is not eligible for the FIT program and, therefore, there are no FIT applications for connection in Remotes' service area;
- Remotes routinely consults with the IESO on various matters as appropriate;
- Each of the communities served by Remotes is electrically isolated and not connected to the bulk transmission system. Therefore, co-ordination with other distributors and/or transmitters on implementing REG investments is not necessary.
- The Remote Community Connection Plan is still under development for Remotes' region.

The letter sent to the IESO is included as Appendix F: Request for IESO Comment Letter and their response is included as Appendix G: IESO Comment Letter.

## 2.3 Performance Measurement for Continuous Improvement (5.2.3)

This section identifies and defines the methods and measures used to monitor distribution system planning process performance, sets targets, reports on historical performance, and explains how this information has been incorporated into the DSP. These address the three performance outcomes listed in the Filing Requirements; customer-oriented performance, cost efficiency and effectiveness, and asset/system operations performance, environmental stewardship, and safety. Table 2-7 summarizes the performance measure to be tracked by Remotes and the desired outcome for each.

Table 2-7: Summary of Performance Measures Tracked by Remotes

<table>
<tr><th>Performance Outcomes</th><th>Performance Categories</th><th>Measures</th><th>Desired Outcome</th></tr>
<tr><td rowspan="4">Customer-oriented Performance</td><td>Customer Satisfaction</td><td>Customer satisfaction survey results</td><td>≥90%</td></tr>
<tr><td>Consumer Bill Impacts</td><td>Percentage annual rate increase</td><td>3% during a Cost of Service year, 2% otherwise</td></tr>
<tr><td rowspan="2">System Reliability</td><td>SAIDI including Loss of Supply</td><td>≤11.24</td></tr>
<tr><td>SAIFI including Loss of Supply</td><td>≤12.97</td></tr>
<tr><td>Cost Efficiency and Effectiveness</td><td>DSP Implementation Progress</td><td>Gross CAPEX + system O&M – planned vs. actual</td><td>≥90%</td></tr>
<tr><td rowspan="4">Asset/System Operations Performance</td><td>Distribution Losses</td><td>Percentage line loss</td><td>≤3.6%</td></tr>
<tr><td>Diesel Generation Efficiency</td><td>Energy generated from diesel per liter of fuel</td><td>≥3.42 kWh/L</td></tr>
<tr><td>Percentage of Energy Generated from Renewables</td><td>Energy generated per liter of fuel issued (includes non-diesel)</td><td>≥2.41%</td></tr>
<tr><td>Generation Availability</td><td>Percentage of generation availability</td><td>≥99.94%</td></tr>
<tr><td rowspan="5">Environmental Stewardship</td><td rowspan="3">Environmental Protection</td><td>Litres lost to the environment</td><td>≤100</td></tr>
<tr><td>Number of spills</td><td>≤6</td></tr>
<tr><td>Number of category A spills</td><td>0</td></tr>
<tr><td rowspan="2">Greenhouse Gas Emission</td><td>Emission of carbon dioxide equivalents</td><td>Monitor emissions and calculate net emission intensity</td></tr>
<tr><td>Net emission intensity</td><td>≤0.000731 tonnes per kWh</td></tr>
<tr><td rowspan="2">Safety</td><td>Lost-time Injuries</td><td>Number of lost-time injuries</td><td>0</td></tr>
<tr><td>Total Recordable Injuries</td><td>Number of recordable injuries</td><td>≤2</td></tr>
</table>

### 2.3.1 Customer-oriented Performance

Customer focus is a key outcome of the RRFE. Therefore, Remotes has identified several measures for customer-oriented performance in the categories of customer satisfaction, consumer bill impacts, and system reliability.

#### 2.3.1.1 Customer Satisfaction

The satisfaction of its customers is very important to Remotes. The motivation for tracking this metric is based on consumer, regulatory, and corporate drivers.

##### 2.3.1.1.1 Definition (5.2.3a)

Customer survey results are used to gain insights into Remotes' performance relative to customers' needs and expectations. Customer surveys have been conducted approximately every two years since 2003. In 2015, Viewpoints Research conducted its most recent telephone survey of 205 residential, business, and government-supported organization customers served by Remotes.

Customer satisfaction is measured as the percentage of customers who responded "very satisfied" or "satisfied" with the electrical service they receive from Remotes, as reported in the customer satisfaction survey. Remotes' target for overall satisfaction is to be greater than or equal to 90 per cent.

##### 2.3.1.1.2 Historical Performance (5.2.3b)

Figure 2-2 depicts the customer satisfaction survey results for each year of the survey.

Figure 2-2: Customer Satisfaction with Electrical Service

Overall satisfaction with the electrical service received from Remotes in 2015 is 91%, which is above the target. This is similar to levels recorded in 2009 and 2011 but is down from the 97% reported in the previous survey.

#### 2.3.1.1.3 Effects on the DSP (5.2.3c)

Customers were asked to indicate the primary reason(s) for satisfaction with Remotes. Table 2-8 summarizes the reasons for satisfaction cited by customers.

Table 2-8: Reasons for Customer Satisfaction

| Reasons for satisfaction | 2015 | 2013 | 2011 | 2009 | 2007 | 2005 | 2003 |
|---|---|---|---|---|---|---|---|
| Electricity there when needed | 65% | 51% | 49% | 40% | 42% | 43% | 43% |
| Good/improved service | 20% | 15% | 26% | 18% | 20% | 19% | 19% |
| Reliability has improved | 12% | 17% | 25% | 20% | 12% | 10% | 10% |
| Fair rates | 4% | 6% | 10% | 5% | 5% | 6% | 6% |
| Customer service | 10% | 10% | 11% | 13% | 3% | 4% | 4% |
| Company doing the best they can | 4% | 2% | 6% | 5% | 3% | 4% | 4% |
| Environmental practices | 0% | 1% | 2% | 2% | <1% | 1% | 1% |
| Rates/problems not their fault | 1% | NA | NA | NA | NA | NA | NA |
| No reason/other/unsure | 12% | 19% | 10% | 27% | 26% | 26% | 26% |

*Percentages do not total 100% because customers were permitted more than one response.*

Having electricity available when they want it continues to be the main driver of customer satisfaction, as was identified by 65% of the surveyed utilities. This is 14% more than the previous survey in 2013, and 25% more than in 2009.

Twenty per cent of customers attributed their satisfaction to good or improved service, and 12% listed improved reliability. Satisfaction with customer service has held steady during this time, with ten per cent of customers indicating this as a key reason for their satisfaction.

The results indicate a need to continue to invest in system reliability as the main driver for customer satisfaction. Remotes has identified several investments over the forecast period planned to improve reliability. Distribution System Improvements replace defective poles, restring conductors, and re-align poles based on asset condition, to improve the system's reliability during storms. Distribution System Improvements also include the installation of new Viper switches to isolate upstream customers from downstream power outages. On the generation side, Remotes performs generator replacements and overhauls in accordance with manufacturer's recommendations to maintain the reliability of its supply. While not primarily driven by reliability improvements, generator upgrade projects have the added benefit of improved power supply reliability.

#### 2.3.1.2 Consumer Bill Impacts

Remotes understands that the cost of living in the north is high. Remotes dedicates significant efforts to keep monthly bills affordable and works with its customers to facilitate timely bill payments. Remotes helps its customers conserve electricity, arrange payment programs, and find programs and services to reduce the overall cost of electricity. The motivation for tracking this metric is based on consumer and legislative drivers.

##### 2.3.1.2.1 Definition (5.2.3a)

Remotes tracks the percentage of annual rate increase for the total bill payable by a typical year-round residential customer who consumes 750 kWh/month. The bill impact for all customers, including residential, is limited to the average distribution increase in a Cost of Service year, historically about three per cent, and by inflation in other years, historically about two per cent, based on legislative requirements.

##### 2.3.1.2.2 Historical Performance (5.2.3b)

The 2013 rate year was the last Cost of Service application for Remotes. and a typical year-round residential customer (750 kWh/month consumption) would have seen a 3.41% bill increase. Table 2-9 depicts the annual percentage bill increase for a year-round residential customer each year from 2013 to 2017, as well as the five-year average.

Table 2-9: Annual Bill Impacts for a Year-Round Residential Customer (2013-2017)

| Year | 2013 | 2014 | 2015 | 2016 | 2017 | 5-year Average |
|---|---|---|---|---|---|---|
| **Percentage Annual Consumer Bill Increase** | 3.45% | 1.7% | 1.6% | 2.1% | 1.9% | 2.15% |

##### 2.3.1.2.3 Effects on the DSP (5.2.3c)

The projects and programs planned in this DSP have been paced and prioritized with consumer bill impacts in mind. To lessen its rate impacts, Remotes has implemented and will continue to implement several cost-saving measures such as those listed in Section 2.1.2.

#### 2.3.1.3 System Reliability

Remotes' goal is to ensure that the power is there when customers reach for the switch. The motivation for tracking this metric is based on consumer, regulatory, and corporate drivers.

##### 2.3.1.3.1 Definition (5.2.3a)

The key metrics that Remotes tracks to measure reliability are the System Average Interruption Frequency Index ("**SAIFI**"), System Average Interruption Duration Index ("**SAIDI**"), and Customer Average Interruption Duration Index ("**CAIDI**"). SAIFI is the average frequency of sustained power interruptions and is calculated by dividing the total number of customer interruptions over a given year by the total number of customers served. SAIDI is the average outage duration and is calculated by dividing the total number of customer-hours of sustained interruptions over a given year by the number of customers served. An interruption is considered sustained if it lasts for at least one minute. CAIDI reflects the average time for electricity service to be restored following an outage and is calculated by dividing the total customer-hours of sustained interruptions over a given year by the total number of sustained interruptions for that year (also by dividing SAIDI by SAIFI).

Over the historical period, Remotes' targets for SAIDI were 12.4 hours including loss of supply and 5.13 hours excluding loss of supply. Its SAIFI targets were 15.6 interruptions including loss of supply and 3.79 interruptions excluding loss of supply.

Over the forecast period, Remotes' target for SAIDI is 11.24 hours including loss of supply and its target for SAIFI is 12.97 interruptions including loss of supply. Remotes does not maintain a target for SAIDI or SAIFI excluding loss of supply since, from the customers' perspective, the reason for a power outage is not as important as the power outage itself.

Remotes does not set a target for CAIDI since, being the ratio of SAIDI to SAIFI, it is a redundant metric and CAIDI can increase while SAIDI and SAIFI both improve. Moreover, CAIDI was recently removed from the OEB's *Reporting and Record Keeping Requirements*. However, historical information on CAIDI is included for reference, as mandated by the Filing Requirements.

### 2.3.1.3.2 Historical Performance (5.2.3b)

Figure 2-3 and Figure 2-4 show the SAIFI and SAIDI performance with and without loss of supply for the years 2013 to 2016.

Figure 2-3: SAIFI Including and Excluding Loss of Supply (2013-2016)

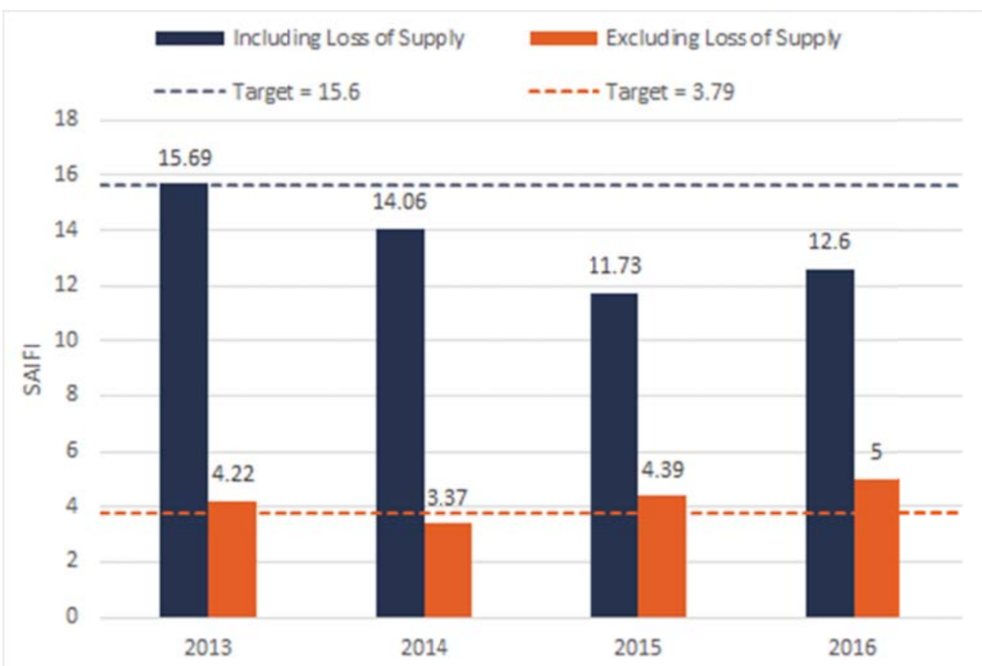
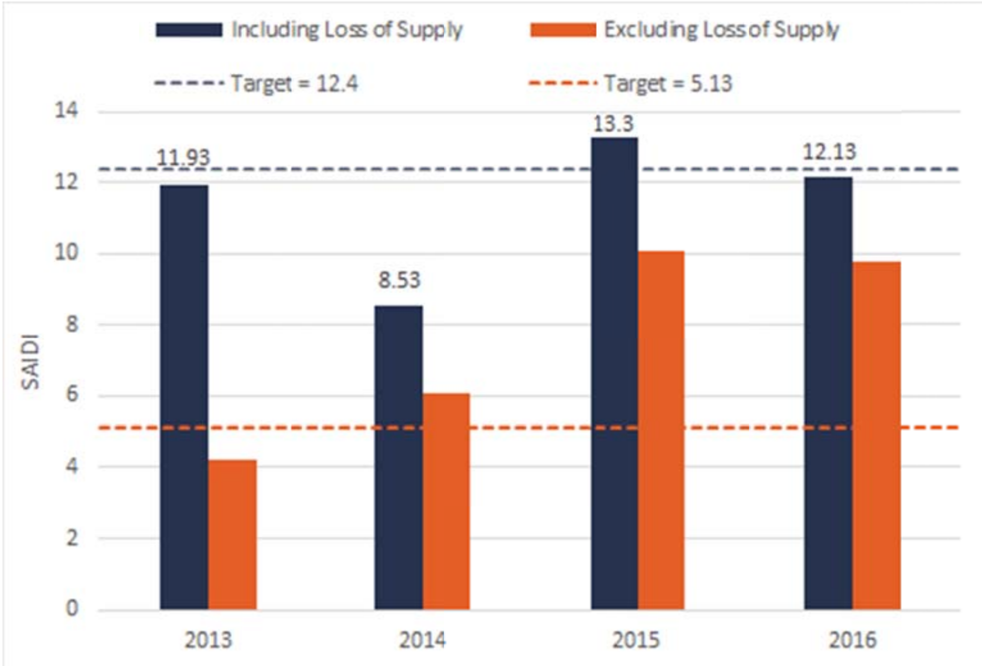


Figure 2-4: SAIDI Including and Excluding Loss of Supply (2013-2016)




When including loss of supply, both the SAIFI and SAIDI are below or very close to the target over the historical period. Excluding it, however, both metrics have exceeded the targets over the past several years, with SAIDI doing so by a significant amount. Based on the IEEE Standard 1366-2012 definition of a Major Event Day (“**MED**”), Remotes has not experienced any MEDs in any of the communities it serves.

Remotes has increased the number of planned distribution outages compared to 2012, which is the primary reason for the above-target performance. In addition, Hillsport had a major outage due to aging equipment where parts are no longer readily available. A new part was able to be fabricated locally to restore equipment to reliable service. This is a small community with just 32 customers, so it would be impractical to allocate a lot of capital to this community. Remotes pre-purchased two new generators so that if one fails it can be replaced by the other. Other material contributing factors to the SAIDI and SAIFI results include a commissioning-related outage at Weagamow, a bulk tank lockout at Deer Lake, an extended outage on the Collins line, and a long outage in Gull Bay.

Table 2-10 and Table 2-11 summarize Remotes’ reliability performance over the historical period of 2013-2016, including CAIDI. The annual performance is highlighted for years when the target was not met.

Table 2-10: Customer Service Indicators Results with Loss of Supply

| Performance Measure | Target | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|
| **SAIDI** | ≤12.4 | 11.93 | 8.53 | 13.3 | 12.13 |
| **SAIFI** | ≤15.6 | 15.69 | 14.06 | 11.73 | 12.6 |
| **CAIDI** | | 0.76 | 0.61 | 1.13 | 0.96 |

Table 2-11: Customer Service Indicators Results without Loss of Supply

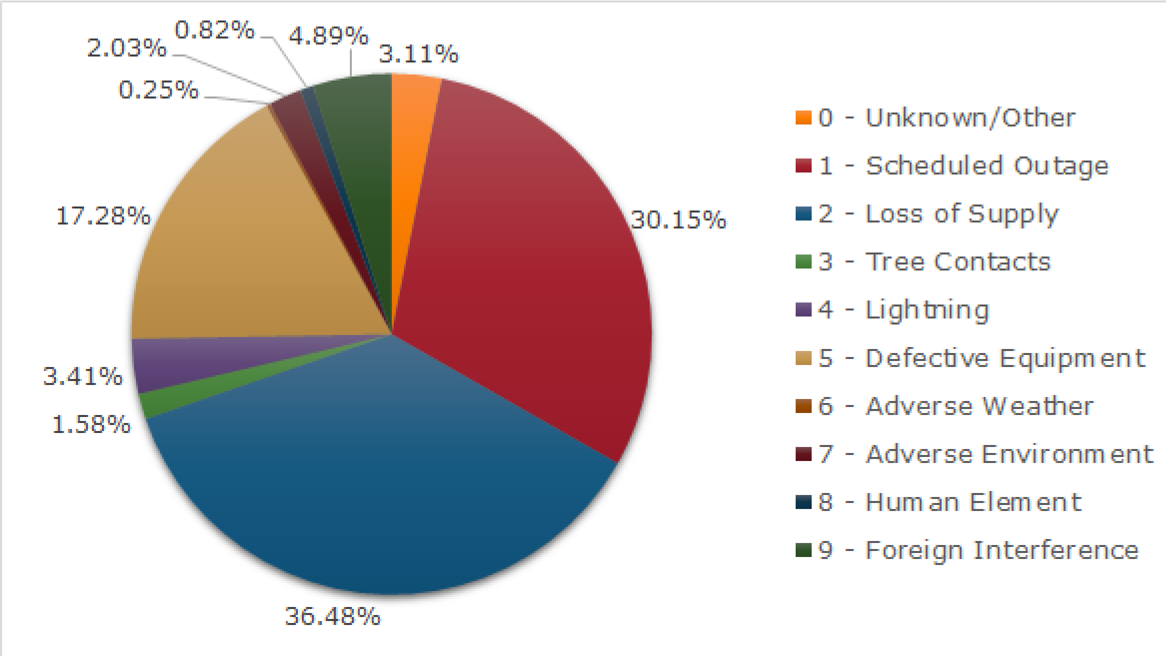
| Performance Measure | Target | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|
| **SAIDI** | ≤5.13 | 4.21 | 6.06 | 10.08 | 9.81 |
| **SAIFI** | ≤3.79 | 4.22 | 3.37 | 4.39 | 5.0 |
| **CAIDI** | | 1.00 | 1.80 | 2.30 | 1.96 |

### 2.3.1.3.3 Effects on the DSP (5.2.3c)

Over the historical period, SAIDI has trended upward while SAIFI has trended downwards. Therefore, while the average duration of interruptions experienced by customers has increased, the average number of outages experienced has decreased. One way to reduce outage durations is through a fast response time. Remotes has a highly trained and skilled workforce including engineers, mechanics, line maintainers, electricians, and technicians stationed in Thunder Bay who are prepared to respond to an emergency 24 hours a day, seven days a week. In addition, there are trained operators in the communities who can respond to outages. However, if skilled trades are required to fix the cause of the outage, transportation can hinder power restoration efforts.

Remotes monitors and analyzes the root cause of power interruptions. Each power outage that occurs on Remotes' distribution system is recorded and an outage cause code is assigned. The number of customer interruption hours for each cause code provides a picture of the root cause of power interruptions. Figure 2-5 depicts the customer interruption duration by cause code for the years 2013 through 2016. The top three categories affecting Remotes' reliability are loss of supply (36.48%), scheduled outages (30.15%), and defective equipment (17.28%).

Figure 2-5: Customer Interruption-Hours by Cause Code (2013-2016)




Loss of supply outages have had the biggest impact on Remotes' customers over the historical period. These outages occur due to problems at the generating station such as the generator, fuel supply system, station auxiliary systems, PLC, circuit breakers, or transformers. Remotes has planned several investments over the forecast period to address loss of supply outages. Generator overhauls are planned to refurbish the engine based on manufacturers' guidelines to maintain the reliable operation of the generator. After two overhauls, it is no longer economical to overhaul the generator and its replacement is planned. Remotes has planned several generator replacements over the forecast period based on the maintenance history of the unit, the number of engine-hours, and the asset condition. SCADA and PLC upgrades at Remotes' generating stations will improve outage response time by enabling remote alarm handling and troubleshooting.

Non-capital investments to reduce loss of supply outages includes planned maintenance on generators as described in Section 3.3.1.2. Remotes is in the process of reviewing which maintenance activities will be beneficial to manage its GSUs.

Scheduled outages were a large part of the power interruptions in 2016. Remotes mitigates the impact of these outages through proactive planning and advanced notice with the affected communities. The planning approach of bundling of work in a community should help to reduce the number of outages and duration customers experience on an annual basis.

Defective equipment caused 22% of the power outages affecting customers in 2016. Remotes has planned various projects and programs in the DSP to address defective equipment outages. On the distribution system, investments will be made to replace aging and defective poles, restring conductors, and realign poles. Remotes is also planning to install new Viper switches on its distribution system to protect upstream customers from downstream faults and to improve the cold load pickup capability of the system.

## 2.3.2 Cost Efficiency and Effectiveness

Cost efficiency and effectiveness with respect to planning quality and DSP implementation is an important part of the Filing Requirements. Therefore, Remotes has identified a measure for cost efficiency and effectiveness in the categories of DSP implementation progress.

### 2.3.2.1 DSP Implementation Progress

DSP implementation progress measures the success of the execution of the capital programs outlined in the DSP. The motivation for tracking this metric is based on regulatory and corporate drivers.

#### 2.3.2.1.1 Definition (5.2.3a)

The metric used is actual gross capital spending and O&M as a percentage of the business plan. The target going forward is based on the historical period average: 90% or more, and reflects the uncertain amounts and timing of INAC funding, as well as contingencies related to the transportation of materials to the north.

#### 2.3.2.1.2 Historical Performance (5.2.3b)

Historical performance is displayed in Table 2-12. The percentage of spending relative to plan varies due to reprioritization of work priorities during the year. Remotes' top priority is to keep the lights on and respond to trouble calls on the systems. The next priority is customer-requested work including connections and capacity upgrades. Since these projects are externally-initiated, Remotes' resources may be redeployed from planned capital projects to accommodate customer needs.

Table 2-12: Actual Spending as Percentage of Business Plan

| Program | Historical | | | | |
|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | Average |
| **Distribution** | | | | | |
| Distribution O&M | 80.30% | 94.85% | 92.64% | 87.39% | 88.80% |
| Distribution Capital | 91.89% | 73.92% | 82.87% | 80.56% | 82.31% |
| **Total Distribution** | 83.28% | 88.85% | 89.96% | 85.47% | 86.89% |
| **Generation** | | | | | |
| Generation O&M | 101.65% | 104.82% | 81.19% | 81.79% | 92.36% |
| Generation Capital | 64.65% | 68.32% | 141.54% | 114.10% | 97.15% |
| **Total Generation** | 88.48% | 92.74% | 98.24% | 89.09% | 92.14% |
| **Other** | | | | | |
| Common O&M | 109.35% | 77.40% | 75.45% | 57.95% | 80.04% |
| Environment O&M | 120.09% | 115.54% | 100.60% | 107.50% | 110.93% |
| Facilities Capital | 47.59% | 78.55% | 15.06% | 128.03% | 67.31% |
| MFA Capital | 214.47% | 93.66% | 131.21% | 62.96% | 125.57% |
| **Total Other** | 92.41% | 96.67% | 61.20% | 101.14% | 87.85% |
| **Total Projects** | 88.76% | 92.30% | 89.73% | 89.57% | 90.09% |

#### 2.3.2.1.3 Effects on the DSP (5.2.3c)

Remotes’ DSP has been informed by the targets derived based on historical performance measurement. Remotes carefully plans project expenditures through its budgeting process. Distribution capital investments have been planned in such a manner that they can be executed by Remotes’ crews, apprentices and casual staff. Generation capital investments have been planned through considerable coordination with INAC and the remote communities. Remotes’ generation capital budgeting process allows for investments to shift between communities as their needs evolve over the forecast period.

## 2.3.3 Asset/System Operations Performance

Asset/system operations performance provides a good measurement of Remotes’ asset management strategy effectiveness. Therefore, Remotes has identified several measures for asset/system operations performance in the categories of distribution losses, diesel generation efficiency, total generation efficiency, and generation availability.

### 2.3.3.1 Distribution Losses

Losses on the distribution system increase the amount of energy generation required to serve the downstream load. Distribution losses should be minimized wherever possible. The motivation for tracking this metric is based on corporate drivers.

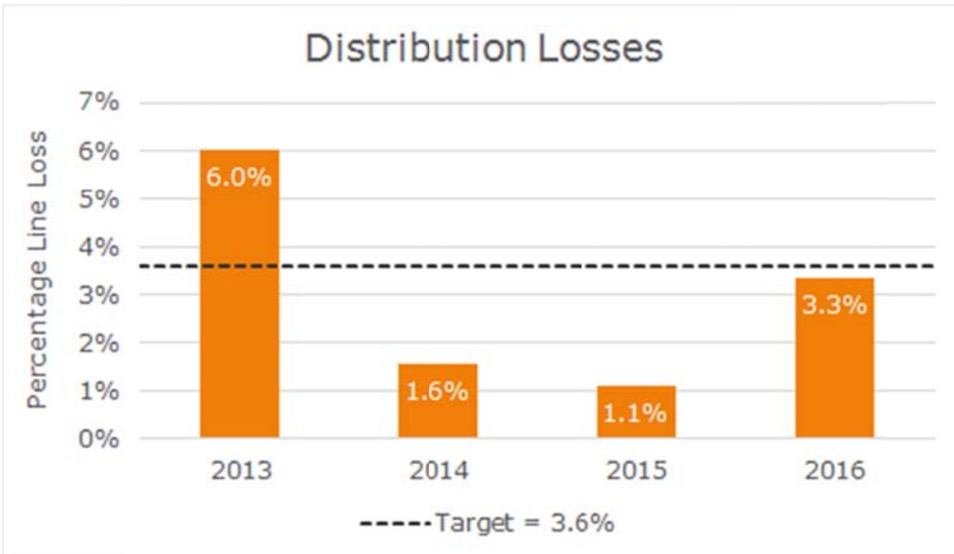
#### 2.3.3.1.1 Definition (5.2.3a)

Remotes tracks its distribution losses as the difference between the energy generated and energy sold, measured as a percentage of the total energy generated (all in kWh). The target for this metric is 3.6% or less.

#### 2.3.3.1.2 Historical Performance (5.2.3b)

The distribution losses over the last four years are presented in the figure below. Remotes exceeded its target in 2013, but has met the target since.

Figure 2-6: Distribution Losses 2013-2016




#### 2.3.3.1.3 Effects on the DSP (5.2.3c)

Remotes has not planned any investments with distribution losses as the primary driver; however, Distribution System Improvements such as conductor restringing and distribution transformer replacements reduce losses on the distribution system.

### 2.3.3.2 Diesel Generation Efficiency

Remotes strives to improve the efficiency of its diesel generation fleet through its procurement process, maintenance programs, and capital investment strategies. The motivation for tracking this metric is based on corporate drivers.

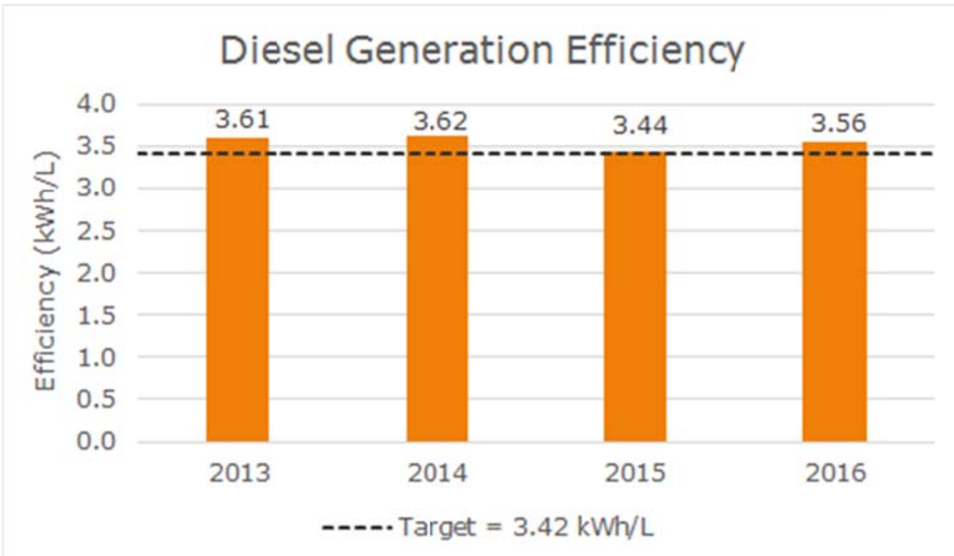
#### 2.3.3.2.1 Definition (5.2.3a)

Remotes calculates its generation efficiency as the amount of energy generated (in kWh) per litre of fuel consumed. The annual target for this metric is an average of 3.42 kWh per litre or greater.

#### 2.3.3.2.2 Historical Performance (5.2.3b)

Figure 2-7 depicts the efficiency of diesel generation for the years 2013 to 2016. The diesel generation efficiency is above target each year but has trended slightly downward since 2013. Diesel generation efficiency depends largely on the load profile in the community as optimized by the generator control scheme. Efficiency also depends on the number of out-of-service units.

Figure 2-7: Diesel Generation Efficiency 2013-2016




#### 2.3.3.2.3 Effects on the DSP (5.2.3c)

To reverse the downward trend, Remotes will continue to invest capital into generation replacements and overhauls. Generator replacements planned over the forecast period replace older, less efficient generators with newer, more efficient ones. Generator overhauls planned over the forecast period improve the efficiency of the refurbished units. While not a significant driver for the investment, generator upgrades have the same efficiency benefit as the replacement projects. The generator upgrades are contingent on INAC funding.

### 2.3.3.3 Percentage of Energy Generated using Renewables

By investing in non-diesel generation assets, such as wind, solar, and hydroelectric, Remotes can reduce its reliance on diesel fuel, which is important to Remotes' customers.

#### 2.3.3.3.1 Definition (5.2.3a)

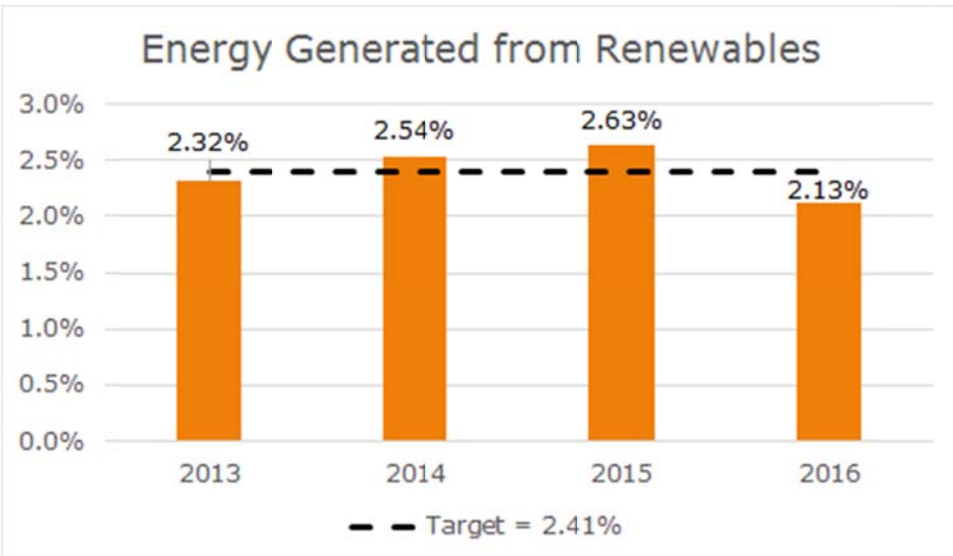
The percentage of energy generated using renewables is calculated by dividing the kWh generated from wind, solar, and hydroelectric sources (owned by Remotes) by the total kWh of energy generated by Remotes. The target over the forecast period is based on the historical period average: 2.41% or greater.

#### 2.3.3.3.2 Historical Performance (5.2.3b)

Remotes currently owns three hydroelectric stations and four wind turbines. Remotes does not currently own any solar generation equipment, but projects in Fort Severn and Gull Bay are currently planned. Fifteen customer-owned solar installations are in service and more are planned.

Figure 2-8 depicts the percentage of energy generated from renewables for the years 2013 through 2016. The amount of energy generated each year fluctuates based on the demand in the community and, in the case of the wind turbines, due to intermittency of the source. The percentage of energy generated from renewables also depends on the condition of the generating units. Recent projects have refurbished, rebuilt, and overhauled the renewable generators to improve their condition. The drop in 2016 is largely due to less energy generated from the Deer Lake hydroelectric generators. In 2016, Deer Lake generated 31% of its total energy from renewable sources, which is close to the previous three-year average of 28%. However, total energy consumption in Deer Lake in 2016 was 21% less than the previous three-year average. Since 65% of Remotes' renewable generation capacity is installed in Deer Lake, the community's consumption affects the metric.

Figure 2-8: Percentage of Energy Generated from Renewable Sources (2013-2016)




#### 2.3.3.3.3 Effects on the DSP (5.2.3c)

There are no capital investments into the existing renewable generator fleet planned over the forecast period, since refurbishments are to be made over the forecast period. Remotes will continue to maintain its renewable fleet to ensure its reliable operation. Several studies are underway to install biomass and solar projects in three remote communities, as described in Section 2.2.1.4.

### 2.3.3.4 Generator Availability

Generation availability is a good indicator of the success of Remotes' capital and maintenance programs and provides an indicator for power reliability. The motivation for tracking this metric is based on consumer and corporate drivers.

#### 2.3.3.4.1 Definition (5.2.3a)

Generation availability is calculated annually using the total duration of unplanned outages over the year. The availability is then the number of hours of unplanned outages subtracted from the number of hours in the year, as a percentage of the total number of hours in the year. Remotes' target for this metric over the forecast period is based on the historical period average: 99.94% or greater.

#### 2.3.3.4.2 Historical Performance (5.2.3b)

The average generation availability for each year of the historical period is shown Table 2-13. Remotes exceeded its target in each of these years

Table 2-13: Percentage of Generation Availability 2013-2016

| Year | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|
| Generation Availability | 99.86% | 99.97% | 99.97% | 99.96% |

The methodology looks at all outages under OEB Cause Code 2 that are one (1) minute or greater.

#### 2.3.3.4.3 Effects on the DSP (5.2.3c)

Similar to system reliability, generation availability drives investment into generation assets. Capital investment into Remotes' generation fleet, through planned replacements and overhauls, addresses generator availability. Generation upgrade projects also improve generation availability, since an older generator is replaced with a newer one and the decommissioned generator can be salvaged for spare parts to enable faster emergency repair times. Remotes' rigorous asset management program includes preventive maintenance on generators, which will reduce generator downtime.

## 2.3.4 Environmental Stewardship

Environmental stewardship is the top priority for many of Remotes' customers. Therefore, Remotes tracks an additional category of measures related to greenhouse gas emissions and environmental protection.

### 2.3.4.1 Greenhouse Gas Emissions

Most of Remotes' electricity is generated using diesel fuel since it is currently the most reliable and cost-effective method. Remotes is cognisant of the greenhouse gas contributions of its fleet and, therefore, monitors its emissions. The motivation for tracking this metric is based on consumer and corporate drivers.

#### 2.3.4.1.1 Definition (5.2.3a)

Remotes tracks greenhouse gas emissions from its electricity generation fleet. Generators within the 19 generating stations burn diesel fuel to produce electricity, directly emitting greenhouse gases to the atmosphere.

The metrics tracked by Remotes that relate to greenhouse gas emissions are:

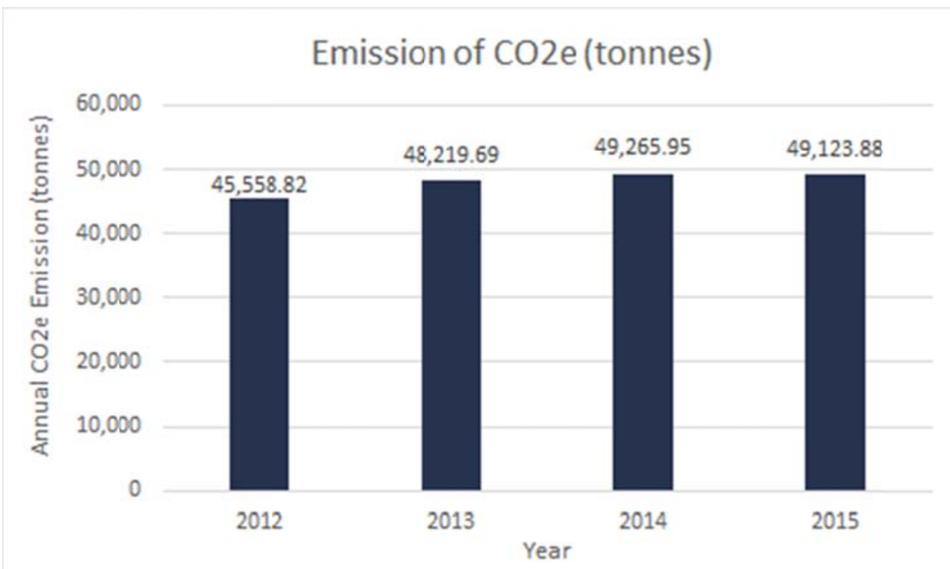
- Emission of carbon dioxide equivalents (“**$CO_2$e**”) measured in tonnes.
- Net emission intensity (tonnes of $CO_2$e per kWh of total energy generated).

The target set for the emission intensity for 2015 is less than or equal to 0.000731 tonnes of $CO_2$e per kWh.

#### 2.3.4.1.2 Historical Performance (5.2.3b)

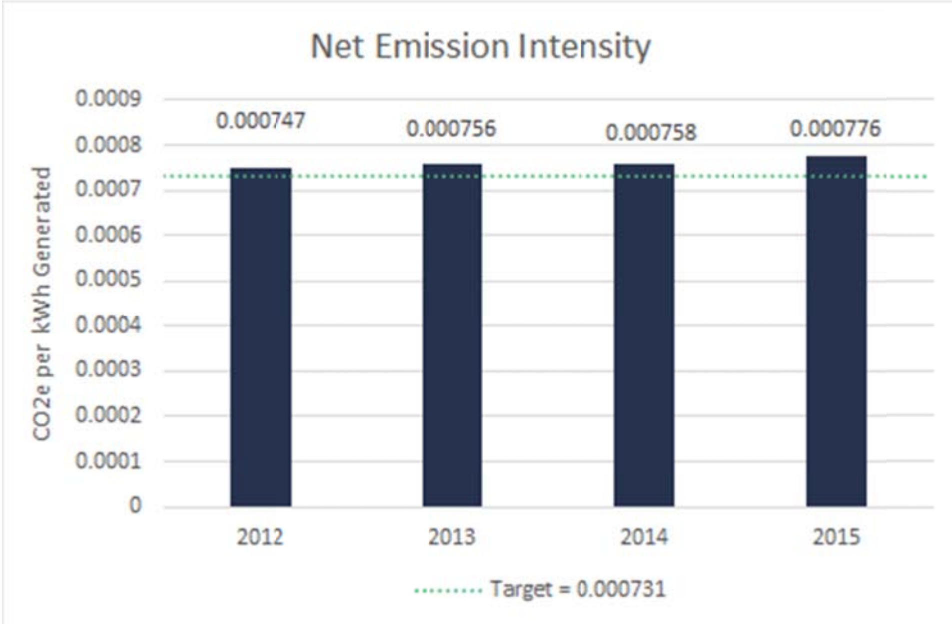
Figure 2-9 shows Remotes’ $CO_2$e emissions from diesel electricity generation over the historical period of 2012 to 2015.

Figure 2-9: Greenhouse Gas Emissions from Generators 2012-2015



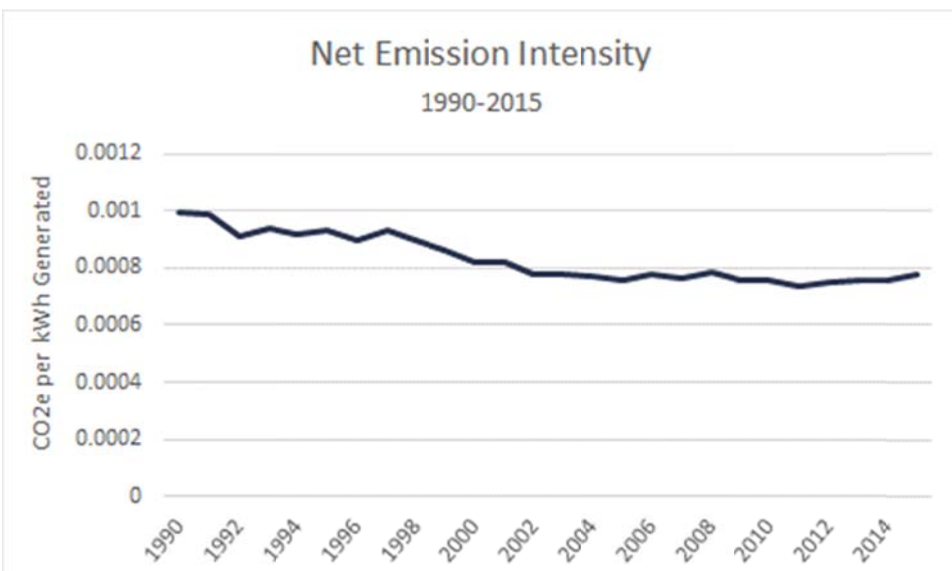

Remotes has increased its direct emissions from electricity generation for the past years. This is due to increases in the electricity demand. Therefore, Remotes’ focus is to reduce its net emission intensity. The net emission intensity for the years is shown in Figure 2-10.

Figure 2-10: Net Emission Intensity from Generators 2012-2015




The net emission intensity has trended upward for the past few years and is above the target. This is due to less energy generated from renewable sources. As mentioned in Section 2.3.3.3, recent refurbishments to the renewable generators are expected to improve their reliability and reduce the net emissions intensity; however, the wind turbine generators will be run to failure since they are not economical to replace. This may affect the net emission intensity.

Figure 2-11: Tonnes of CO2e Emitted per kWh Generated 1990-2015




The long-term trend depicted in Figure 2-11 indicates that significant improvements have been made, but continued innovation is needed to further reduce the net emission intensity.

#### 2.3.4.1.3 Effects on the DSP (5.2.3c)

Remotes has invested in renewable generation and offers the opportunity to purchase renewable electricity from its customers. Remotes is working with many local communities and their partners on high penetration renewable projects to help meet their electricity needs. Improvements in diesel generator technology will also improve the net emission intensity. As Remotes replaces older generators with newer ones through its replacement and upgrade programs and overhauls generators, it is expected that the net emission intensity will decrease.

### 2.3.4.2 Environmental Protection

Remotes works hard to reduce its overall environmental impact and takes environmental protection seriously. Metrics tracked under this category are high-priority to the First Nation communities served by Remotes. The motivation for tracking these metrics is based on legislative, consumer, and corporate drivers.

#### 2.3.4.2.1 Definition (5.2.3a)

The metrics tracked in this category are:

- Litres of fuel lost to the environment
- Number of spills
- Number of Category A spills

The *Ontario Environmental Protection Act* defines "spill" as, when used with reference to a pollutant, means a discharge

1. into the natural environment;
2. from or out of a structure, vehicle, or other container; and
3. that is abnormal in quality or quantity considering all the circumstances of the discharge.

The measure for the number of spills refers only to spills caused by Hydro One Inc. personnel (including Remotes' personnel).

A "Category A" spill is defined as a spill which causes or may cause one or more of the following adverse effects:

1. Widespread injury or damage to plant or animal life.
2. Harm or material discomfort to any person.
3. An adverse effect on the health of any person.
4. The impairment of the safety of any person.

Remotes' annual targets are not more than 100 litres of fuel lost to the environment, not more than six spills, and zero Category A spills.

#### 2.3.4.2.2 Historical Performance (5.2.3b)

Table 2-14 summarizes Remote's environmental protection performance over the historical period.

Table 2-14: Environmental Protection Measures – Historical Performance

| | Target | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|
| **Litres of fuel lost to the environment** | ≤100 | 0 | 10 | 20 | 0 |
| **Number of spills** | ≤6 | 2 | 4 | 8 | 0 |
| **Number of Category A spills** | 0 | 0 | 0 | 0 | 0 |

In 2015, there was an increase in the number of spills reported due to:

- Renewed commitment on self-reporting including small spills.
- Training and education of both staff and operators on proper reporting procedure.
- Increase in transportation work equipment ("**TWE**"), therefore more TWE spills.
- Increase in coolant/antifreeze spills related to equipment failures.

As of 2015, staff and contractors were trained to report all spills, no matter how small, including emissions or stains from a parked TWE and small spills within the diesel generating station, which Remotes staff previously just cleaned up.

#### 2.3.4.2.3 Effects on the DSP (5.2.3c)

Several projects and programs planned over the forecast period reduce the risk of spills or fuel lost to the environment. Several projects will replace bulk and day fuel tanks to bring them up to compliance and reduce the risk of a spill. Generator replacement, overhaul, and upgrade projects reduce the risk of fuel being lost of a spill occurring from the generator itself. On the distribution side, Distribution System Improvements replace distribution transformers showing signs of oil leak or significant deterioration.

## 2.3.5 Safety

Safety is very important to Remotes. In addition to including safety in its Corporate Mission and Corporate Values, Remotes tracks safety metrics on its scorecard.

### 2.3.5.1 Employee Safety

Remotes continuously strives for an injury-free workplace and measures employee safety in terms of lost-time injuries and recordable injuries.

#### 2.3.5.1.1 Definition (5.2.3a)

The Workplace Safety and Insurance Board defines a lost-time injury as "when a worker suffers a work-related injury/disease which results in being off work past the day of accident, loss of wages/earnings, or a permanent disability/impairment". Remotes strives for zero lost-time injuries.

The U.S. Department of Labor's Occupation Health and Safety Administration defines a recordable injury as one that results in "death, days away from work, restricted work or transfer to another job, medical treatment beyond first aid, or loss of consciousness" and may also include "a significant injury or illness diagnosed by a physician or other licensed health care professional" even if it does not meet the aforementioned criteria. Remotes strives for less than two recordable injuries per year.

### 2.3.5.1.2 Historical Performance (5.2.3b)

The number of lost-time injuries for the years 2013 through 2016 is shown in Table 2-15. In 2013, employees experienced two exertion injuries and one slip/trip/fall that required medical attention.

Table 2-15: Employee Safety over the Historical Period

| | Target | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|
| **Number of lost-time injuries** | 0 | 0 | 0 | 0 | 0 |
| **Number of recordable injuries** | ≤2 | 3 | 1 | 1 | 0 |

### 2.3.5.1.3 Effects on the DSP (5.2.3c)

Safety is considered when planning any job; from the simplest repair to the most complicated capital construction. At a minimum, no project or program compromises safety. From a capital planning perspective, the proactive replacement of generation and distribution assets improves safety by reducing the probability of an incident due to an unplanned failure.

# 3 Asset Management Process (5.3)

Remotes' asset management process is the systematic approach used to plan and optimize ongoing capital and O&M expenditures on the isolated electrical systems it owns (i.e. generation and distribution assets). The purpose of this section is to provide the OEB and other stakeholders with an understanding of Remotes' asset management process, as well as direct links between the process and the expenditure decisions that comprise Remotes' capital investment plan.

## 3.1 Asset Management Process Overview (5.3.1)

This section presents Remotes' asset management objectives and the components of Remotes' asset management process.

### 3.1.1 Asset Management Objectives (5.3.1a)

Remotes applies established asset management principals in managing its assets. The management of Remotes' assets involves optimizing and sustaining the assets over their lifecycles and factors in performance, cost, and risk. The management of the assets is carried out consistent with Remotes' strategic direction.

Remotes' vision is to be the leading utility and a trusted partner to remote communities in Ontario's north. Its mission is to supply safe, reliable, and affordable electricity to remote communities by focusing on continuous improvement, operational excellence, and outstanding customer service.

Remotes' strategic asset management objectives are divided into four categories of strategic business values: health and safety, stewardship, excellence, and innovation. The objectives are derived from the following corporate mission and vision statements. They are ranked as follows:

**1. Health and Safety**

- Ensure public and worker health and safety.

**2. Stewardship**

- Align development work with government policies, priorities, and directives.
- Ensure safe, reliable and efficient operation of the Remotes' system.
- Ensure long-term sustainability of existing assets and equipment; system reliability and security; and customer satisfaction and environmental integrity.
- Meet all applicable regulatory, legal and industry requirements.
- Enable and facilitate efficient connection of customers and maximize connection of renewable resources.
- Facilitate and enable the effective transformation and re-configuration of Remotes' system into a modern, intelligent, and customer-centric system.
- Ensure compliance in meeting potential new environmental air emission requirements.
- Manage existing assets consistent with Remotes' environmental management system and with a strong focus on energy efficiency.

- Keep informed and identify potential integration options into the grid, and assess if there is a strong business case.
- Maximize/optimize useful asset life for overall cost-benefit by balancing competing requirements for operating performance, costs, and risks.
- Keep informed of Smart Grid advancement for appropriate application at the Remotes' distribution system.
- Level and prioritize sustainment work scope and volumes for greater effectiveness and flexibility within applicable resource constraints (e.g., financial, staff).
- Develop the Remotes' system with a strong focus on energy efficiency, environmental awareness, and meeting potential new environmental air emission requirements.
- Maintain an appropriate balance and flexibility between sustainment and development work.
- Discuss and collaborate with affected First Nations and Métis communities on development.
- Discuss and collaborate with affected public and stakeholders on related Remotes development.
- If directed by the government; manage existing third party remote community energy systems.

**3. Excellence**

- Develop, retain, and have available a skilled, trained, productive, and flexible workforce for sustainment work, development work, and operating work.
- Focus on properly-planned and preventive work which emphasizes excellence and safety in achieving results, while eliminating 'firefighting' and corrective maintenance.
- Ensure the effective development of modern, reliable, cost- effective, safe, efficient and flexible systems which are customer-oriented and meets customers' needs.
- Develop and operate the Remotes' system and manage existing assets, using quality information, including databases, information systems and processes.

**4. Innovation**

- Leverage innovative and practical technologies, processes and standards in the development and operation of Remotes' system, and to improve asset and system performance, operations, and maintenance.
- Leverage effective and innovative ways and means to meet the needs of customers, including customer choice and the enablement of value services to the customers.
- Demonstrate leadership in Remotes' system technology advancement.

### 3.1.2 Components of the Asset Management Process (5.3.1b)

Figure 3-1 depicts Remotes' asset management process for diesel generators, including the role of the Asset Condition Assessment ("**ACA**"). Diesel generators are maintained as per manufacturer-published recommendations, including complete overhauls after specified hours. After two (2) overhauls, a diesel generator is typically replaced as the lifecycle has then been extended twice, parts can become obsolete and to improve fuel efficiency. Some units may be identified for earlier replacement subject to specific issues discovered during its lifecycle. Replacement may be advanced or lengthened accordingly. The engine replacement program also includes work related to auxiliaries and sometimes station transformers and breakers. Auxiliary work is evaluated on a case-by-case basis given the site, the existing equipment in service and the proposed replacement. In the past, strong community load growth has triggered frequent station upgrades which involve replacing diesel generators prior to them reaching their full life term.

Figure 3-1: Remotes' Asset Management Process for Diesel Generators

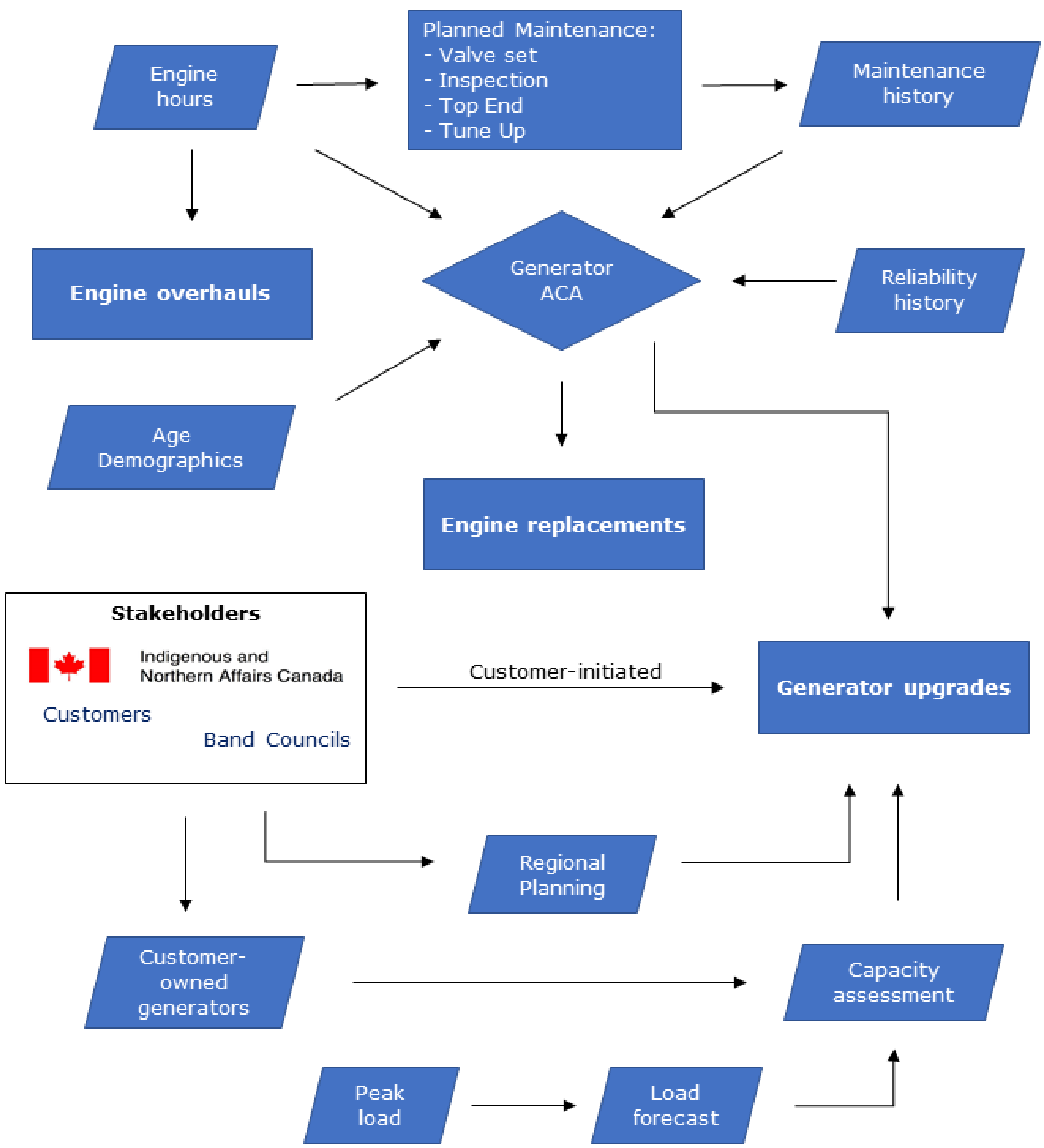


Figure 3-2 and Figure 3-3 depict Remotes' asset management process for its hydroelectric generators and wind turbines, respectively. Both types of generators undergo maintenance every six months. Capital work for hydroelectric generators, including replacement or refurbishment, is planned based on the ACA. The wind turbines owned by Remotes are run to failure.

Figure 3-2: Remotes' Asset Management Process for Hydroelectric Generators

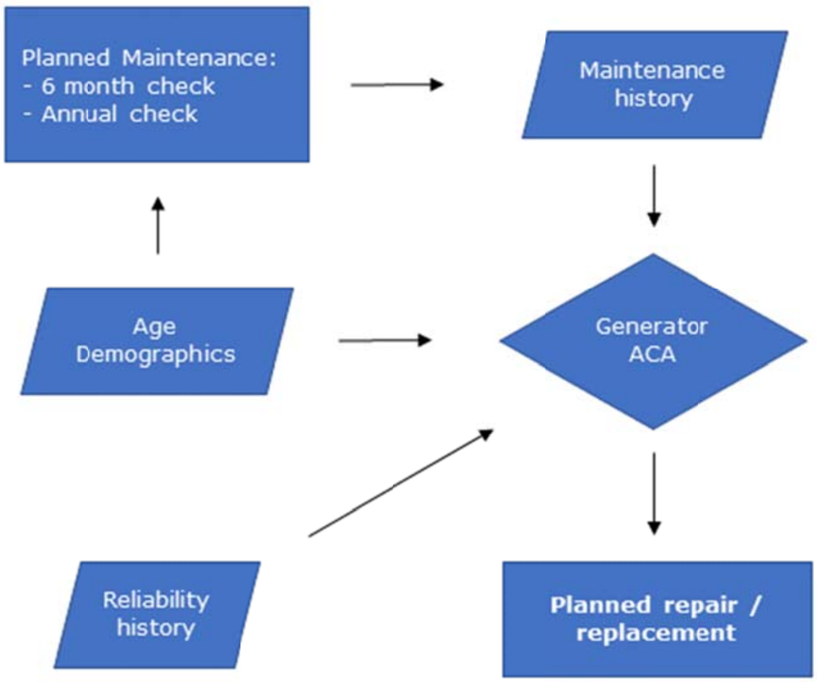
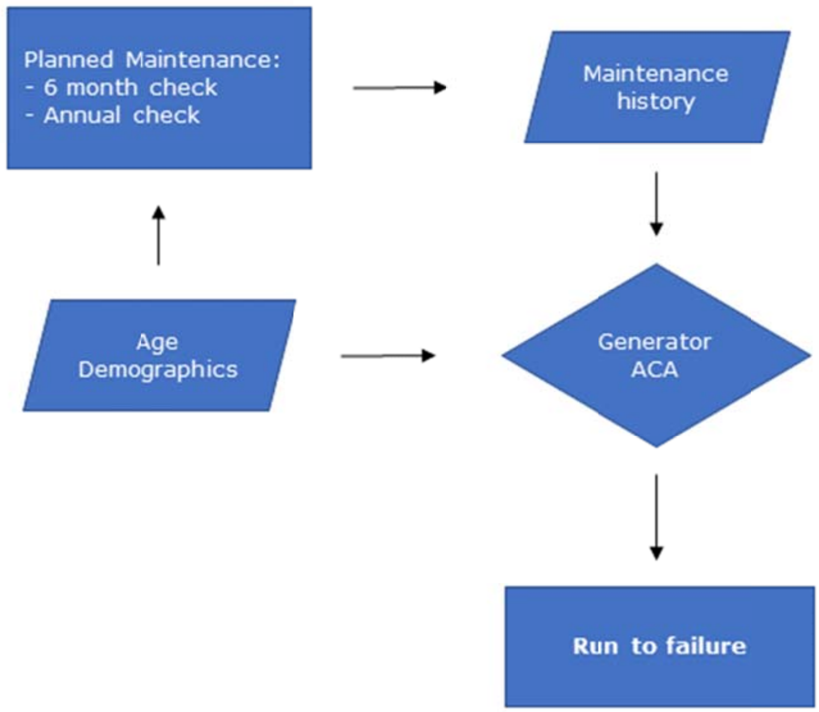
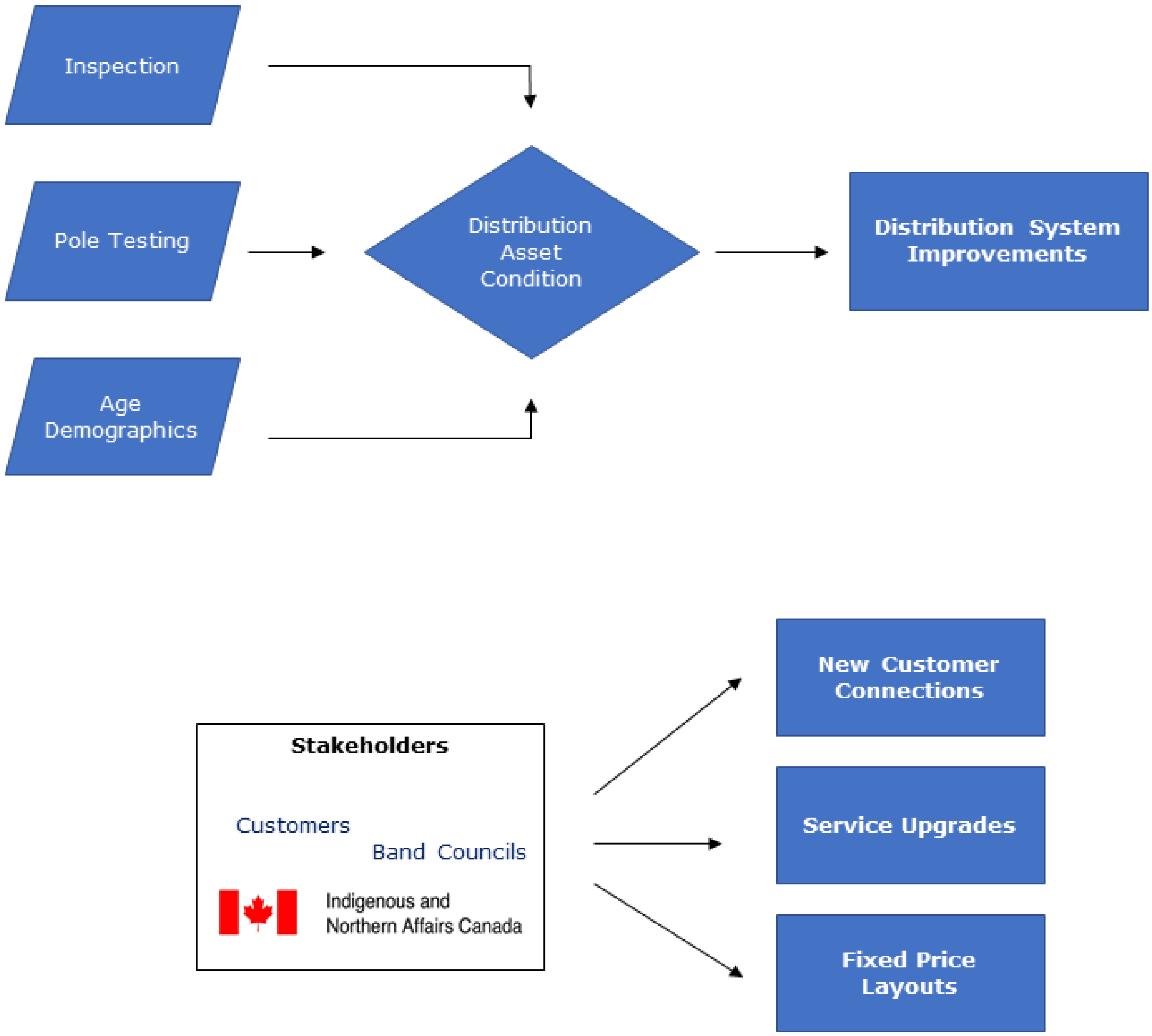


Figure 3-3: Remotes' Asset Management Process for Wind Turbines




On the distribution side, a community is selected for a betterment project each year based on asset condition, demographics and inspection results. This includes work such as pole replacements, conductor restringing, and pole re-alignment. New customer connections, service upgrades, and fixed price layouts are planned based on customer input. Figure 3-4 depicts Remotes' distribution asset management process.

Figure 3-4: Remotes' Distribution Asset Management Process



## 3.2 Overview of Assets Managed (5.3.2)

This section presents a description of Remotes' service area, a summary of the system configuration, demographic and condition information for major distribution and generation assets, and the system utilization relative to planning criteria.

### 3.2.1 Description of the Service Area (5.3.2a)

Remotes' distribution system serves 21 remote communities, each with specific needs. Nineteen of these sites have stand-alone generation systems. These communities are comparatively small and most do not have year-round road access. As a predominantly isolated and remote distribution system, Remotes serves very few customers spread over a large area.

Remotes' service territory is vulnerable to weather extremes owing to its geographical location in northern Ontario. The ability of staff to respond and repair facilities can be hampered by severe weather, especially with respect to cancelled or delayed flights or a plane's inability to land including when a flight has been attempted. These factors directly impact the reliability of the system.

Owing to Remotes predominantly overhead line distribution system, vegetation management is an important factor in managing reliability impacts and associated costs which may result from tree encroachment and contact with the overhead lines. Regular and routine vegetation management-related maintenance needs to be carried out in a dispersed service territory exposed to tree-related reliability impacts. Based on Remotes' historical performance (see Section 2.3.1.3.3), its vegetation management program has been effective at reducing the number of tree contact outages.

Economic growth in the communities has historically been and is expected to continue to be low. As shown in Table 1-3, a slight growth in the numbers of customers has been forecast in most communities. As customers plug in more devices, electricity usage is becoming more intensive. Table 4-10 presents the resultant peak load forecast for each community based on these factors.

### 3.2.2 Summary of System Configuration (5.3.2b)

#### 3.2.2.1 Distribution

Since the communities serviced by Remotes are far apart and isolated, the distribution systems are separate and independent. The distribution voltage for these distribution systems ranges from 4.16 kV to 27.6 kV. There are approximately 242 kilometres of distribution lines which deliver the electricity to the 21 communities through 19 isolated distribution systems. Each distribution system consists of just one feeder. Table 3-1 summarizes the distribution system configuration.

Table 3-1: Summary of Remotes' Distribution System Configurations

| | |
|---|---|
| Number of 27.6 kV systems | 15 |
| Number of 4.16 kV systems | 4 |
| Total number of distribution systems | 19 |
| Circuit km – 27.6 kV | 220 |
| Circuit km – 4.16 kV | 22 |
| Total km of distribution lines | 242 |

The number of circuit kilometres in the communities anticipated to be added to Remotes' service area over the plan period cannot be readily estimated at this time.

#### 3.2.2.2 Generation

Remotes owns 64 generators, of which 57 run on diesel fuel. They are rated between 60 kW to 1500 kW. Each station houses between two and four diesel generators. Most of the stations have three generators, sized to meet the loads at different times of the day. The generators are automated to run to maximize fuel efficiency by matching generator size to the electricity load of the community. Remotes handles over 17 million litres of diesel fuel each year, depending on the electrical demand of the communities.

Three hydroelectric generators and four wind turbines comprise the remaining generation. The capacities hydroelectric generators range from 150 to 225 kW, while the capacities of the wind turbines range from 10 to 60 kW.

Table 3-2 shows a complete list of Remotes' generators and GSUs by community.

Table 3-2: Generator and GSU Capacity

| Community | Generation Unit | Generator Capacity (kW) | Engine Speed (rpm) | GSU Size (kVA) |
|---|---|---|---|---|
| Armstrong | A | 725 | 1800 | 3 x 333 |
| | B | 725 | 1800 | |
| | C | 1100 | 1800 | |
| Bearskin Lake | A | 600 | 1800 | 3 x 500 |
| | B | 410 | 1800 | |
| | C | 1000 | 1200 | |
| Big Trout Lake | A | 600 | 1800 | 3 x 750 |
| | B | 1000 | 1800 | |
| | C | 1000 | 1200 | |
| | T1 | 400 | 1800 | |
| | WTG#1 | 60 | - | |
| Biscotasing | A | 60 | 1800 | 3 x 250 |
| | B | 96 | 1800 | |
| | C | 143 | 1800 | |
| Deer Lake | A | 1500 | 1200 | 1500 |

| | | | | |
|---|---|---|---|---|
| | B | 635 | 1800 | |
| | C | 1050 | 1800 | |
| | Hydel #1 | 225 | - | |
| | Hydel #2 | 225 | - | |
| Fort Severn | A | 600 | 1200 | 3 x 333 |
| | B | 455 | 1800 | |
| | C | 1000 | 1200 | |
| Gull Bay | A | 450 | 1800 | 500 |
| | B | 180 | 1800 | |
| | C | 250 | 1800 | |
| Hillsport | A | 125 | 1800 | 3 x 50 |
| | B | 125 | 1800 | |
| Kasabonika Lake | A | 1000 | 1200 | 3 x 500 |
| | B | 1450 | 1200 | |
| | C | 600 | 1800 | |
| | WTG#1 | 10 | - | |
| | WTG#2 | 10 | - | |
| | WTG#3 | 10 | - | |
| Kingfisher Lake | A | 455 | 1800 | 3 x 250 |
| | B | 600 | 1200 | |
| | C | 250 | 1800 | |
| Lansdowne House | A | 275 | 1800 | 3 x 333 |
| | C | 600 | 1800 | |
| | D | 600 | 1200 | |
| Marten Falls | A | 650 | 1200 | 3 x 250 |
| | B | 400 | 1800 | |
| | C | 250 | 1800 | |
| Oba | A | 65 | 1800 | 3 x 250 |
| | B | 65 | 1800 | |
| | C | 96 | 1800 | |
| Sachigo Lake | A | 635 | 1800 | 1250 |
| | B | 455 | 1800 | |
| | C | 1050 | 1200 | |
| Sandy Lake | G1 | 1250 | 1200 | 4000 |
| | G2 | 1250 | 1200 | |
| | G3 | 1500 | 1200 | |
| | G4 | 1000 | 1200 | |
| Sultan | A | 150 | 1800 | 3 x 200 |
| | B | 175 | 1800 | |
| | Hydel #1 | 150 | - | |
| Wapekeka | A | 820 | 1200 | 3 x 333 |
| | B | 455 | 1800 | |
| | C | 410 | 1800 | |
| Weagamow | A | 600 | 1800 | 3 x 500 |

| | | | | |
|---|---|---|---|---|
| | B | 725 | 1800 | |
| | C | 400 | 1800 | |
| Webequie | G1 | 400 | 1800 | 1000 |
| | G2 | 600 | 1200 | |
| | G3 | 725 | 1200 | |
| Total Diesel Generation | | 30,960 | | |
| Total Hydroelectric Generation | | 600 | | |
| Total Wind Generation Capacity | | 90 | | |
| **Total Capacity** | | **31,650** | | **22,746** |

In addition, there are three generators in Wunnumin Lake, which Remotes is anticipating it will manage once this community is added to its service area.

### 3.2.3 Asset Demographics and Condition Information (5.3.2c)

The main categories of assets managed by Remotes are:

- Generators
- GSUs
- Poles
- Distribution Transformers

Table 3-3 shows Remotes' current asset count.

Table 3-3: Asset Counts for Major In-service Generation and Distribution Assets

| Generators | GSUs | Poles | Distribution Transformers |
|---|---|---|---|
| 64 | 47 | 4662 | 1138 |

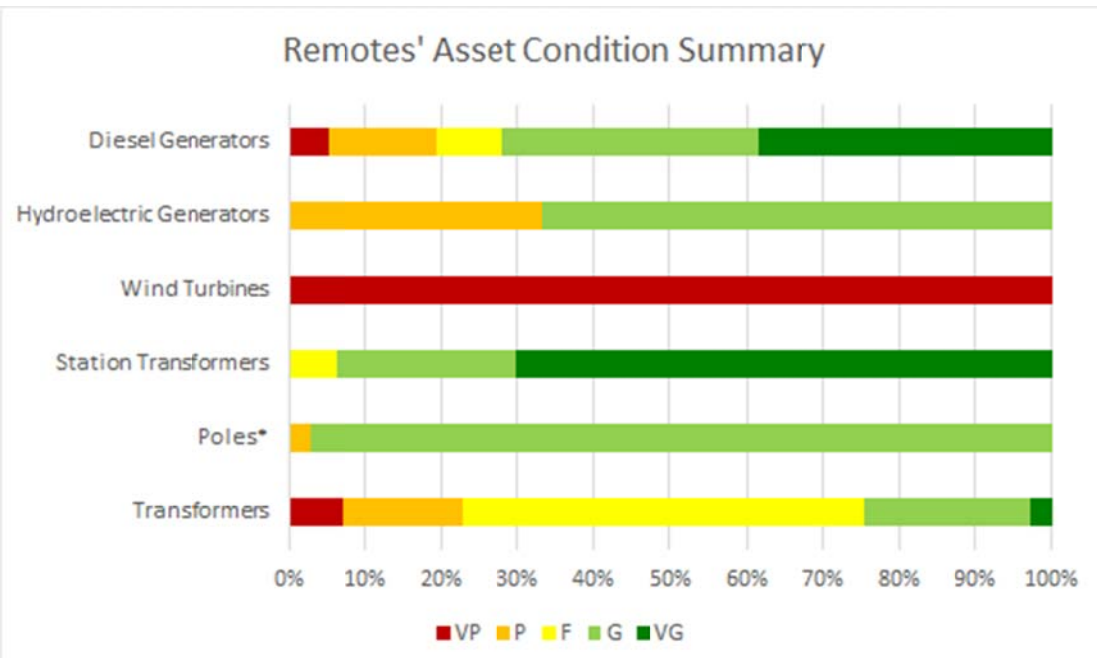
Asset Condition Assessment ("**ACA**") results are based on a consistent approach with the objective of applying a clear and unambiguous interpretation across the asset classes. Assets are divided into five, categories from Very Good to Very Poor based on the definitions in Table 3-4.

Table 3-4: Definition of Asset Conditions

| Condition | Description | Requirements |
|---|---|---|
| Very Good ("**VG**") | Some aging or minor deterioration of a limited number of components | Normal maintenance |
| Good ("**G**") | Significant deterioration of some components | Normal maintenance |
| Fair ("**F**") | Widespread significant deterioration or serious deterioration of specific components | Perform risk assessment; manage risk; consider replacement or refurbishment in five to ten years |
| Poor ("**P**") | Widespread serious deterioration | Plan for replacement or refurbishment within the next five years |
| Very Poor ("**VP**") | Extensive serious deterioration | Plan for immediate replacement or refurbishment |

Figure 3-5 summarizes the condition of Remotes' assets, as compiled on January 2, 2017. Note that poles have only have three condition categories: VP, P, and G.

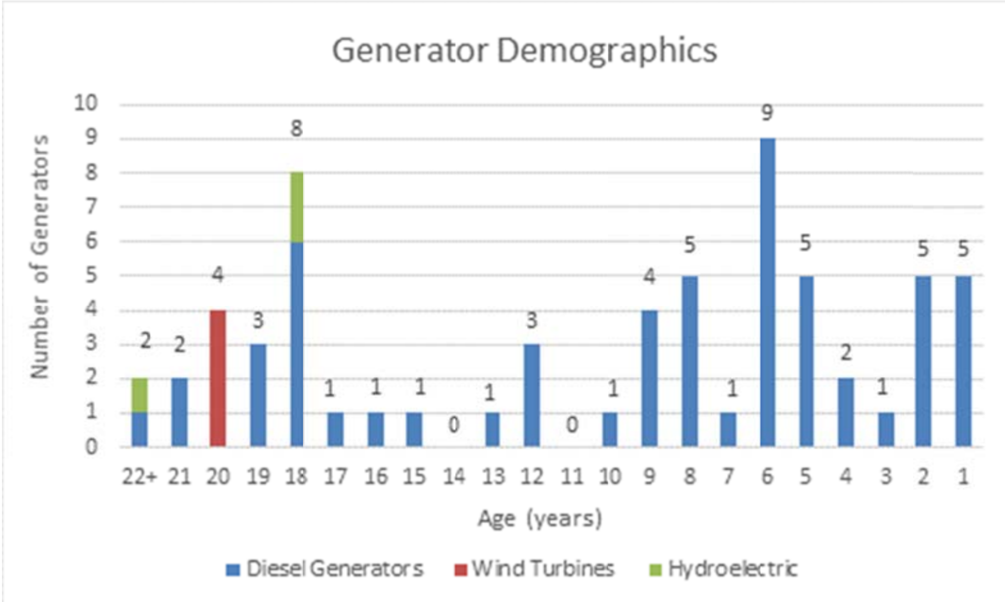
Figure 3-5: Summary of Remotes' Asset Condition Assessment




## 3.2.3.1 Generators

Remotes owns 64 generators, of which 57 run on diesel fuel. The remainder are three hydroelectric generators and four wind turbines. The age demographics for these generators are shown in Figure 3-6.

Figure 3-6: Age Demographics for Generators




The results of the ACA on Remotes' generators – based on engine-hours and operating experience – are summarized in Table 3-5. Table 3-6 presents the detailed in-service year, engine-hours, and condition of each unit. The condition scores of the wind turbines are driven by their ages, but these units are not economical to replace proactively and are run to failure. The conditions of the hydroelectric generators are based on inspections. The poor condition hydroelectric generator in Sultan is being repaired.

Table 3-5: Summary of the ACA for Generators

| | VP | P | F | G | VG |
|---|---|---|---|---|---|
| Diesel Generators | 3 | 8 | 5 | 19 | 22 |
| Hydroelectric | 0 | 1 | 0 | 2 | 0 |
| Wind | 4 | 0 | 0 | 0 | 0 |

Table 3-6: Generator In-service Year, Engine-hours, and Condition

| Community | Generation Unit | In-service Year | Engine-hours | Condition |
|---|---|---|---|---|
| Armstrong | A | 2015 | 7,297 | VG |
| | B | 2011 | 17,014 | G |
| | C | 1999 | 32,988 | F |
| Bearskin Lake | A | 2009 | 42,234 | P |
| | B | 2016 | 1,568 | VG |
| | C | 2000 | 12,508 | VG |
| Big Trout Lake | A | 1996 | 48,064 | VP |
| | B | 2010 | 37,146 | P |
| | C | 2005 | 46,082 | G |
| | T1* | 1999 | 6,431 | VG |

| | | | | |
|---|---|---|---|---|
| | WTG#1 | 1997 | - | VP |
| Biscotasing | A | 2012 | 4,423 | VG |
| | B | 2012 | 24,098 | F |
| | C | 2012 | 16,210 | G |
| Deer Lake | A | 2016 | 476 | VG |
| | B | 2016 | 3,382 | VG |
| | C | 2004 | 37,005 | P |
| | Hydel #1 | 1999 | - | G |
| | Hydel #2 | 1999 | - | G |
| Fort Severn | A | 1998 | 69,212 | F |
| | B | 2012 | 18,884 | G |
| | C | 2015 | 310 | VG |
| Gull Bay | A | 2009 | 12,056 | G |
| | B | 2011 | 31,757 | F |
| | C | 2011 | 10,450 | VG |
| Hillsport | A | 2007 | 43,474 | P |
| | B | 2001 | 64,034 | VP |
| Kasabonika Lake | A | 1998 | 73,818 | P |
| | B | 2015 | 923 | VG |
| | C | 2009 | 18,177 | G |
| | WTG#1 | 1997 | - | VP |
| | WTG#2 | 1997 | - | VP |
| | WTG#3 | 1997 | - | VP |
| Kingfisher Lake | A | 2009 | 34,684 | F |
| | B | 1999 | 38,611 | G |
| | C | 2005 | 9,629 | VG |
| Lansdowne House | A | 2015 | 1,784 | VG |
| | C | 2014 | 16,246 | G |
| | D | 1999 | 11,909 | VG |
| Marten Falls | A | 1982 | 77,247 | P |
| | B | 2005 | 61,728 | VP |
| | C | 2016 | 18,708 | G |
| Oba | A | 2011 | 21,369 | G |
| | B | 2011 | 17,844 | G |
| | C | 2011 | 5,856 | VG |
| Sachigo Lake | A | 2013 | 11,567 | VG |
| | B | 2009 | 23,542 | G |
| | C | 2002 | 24,688 | G |
| Sandy Lake | G1 | 2008 | 40,431 | G |
| | G2 | 2008 | 23,256 | VG |
| | G3 | 2013 | 6,942 | VG |
| | G4 | 2008 | 45,627 | G |
| Sultan | A | 1999 | 45,271 | P |
| | B | 1998 | 45,194 | P |

| | | | | |
|---|---|---|---|---|
| | Hydel #1 | 1982 | - | P |
| Wapekeka | A | 1999 | 47,552 | G |
| | B | 2012 | 11,339 | VG |
| | C | 2015 | 7,657 | VG |
| Weagamow | A | 1996 | 9,487 | VG |
| | B | 2016 | 0 | VG |
| | C | 2008 | 14,596 | G |
| Webequie | G1 | 2011 | 13,731 | G |
| | G2 | 2011 | 28,943 | G |
| | G3 | 2011 | 6,323 | VG |

**temporary unit*

Three of the diesel generators are in Very Poor condition: Big Trout Lake A, Hillsport B, and Marten Falls B. Marten Falls was last overhauled in February 2016 and its replacement is planned for when it reaches 80,000 engine-hours. Remotes is planning to procure a new generator for Big Trout Lake A in 2018 and to replace the unit in 2019. Hillsport B was last overhauled in 2016.

Eight of the diesel generators are in Poor condition: Bearskin Lake A, Big Trout Lake B, Deer Lake C, Hillsport A, Kasabonika A, Marten Falls A, Sultan A, and Sultan B. Bearskin Lake A was last overhauled in 2013. Remotes is planning to replace Big Trout Lake B in 2020. Deer Lake C is scheduled for replacement in 2021 and 2022. Hillsport and Sultan are both small communities that have temporary units that can be moved among the sites to manage the impact of an unplanned failure. A new generator to replace Kasabonika A will be procured in 2022. A new generator Marten Falls A has been procured and its replacement timing is under consideration.

Remotes also projects the number of engine-hours for each of its diesel generators for each year of the forecast period. Table 3-7 presents the year-end forecast for the years 2017 to 2022. A unit is highlighted in red on the year it exceeds the number of manufacturer-recommended engine-hours. Exceeding manufacturer-recommended hours increases the probability of a failure of the unit.

Table 3-7: Forecast Engine-hours for Diesel Generators

| Community | Generation Unit | Forecast Engine-hours | | | | | |
|---|---|---|---|---|---|---|---|
| | | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Armstrong | A | 12,142 | 16,961 | 21,781 | 26,601 | 31,421 | 36,240 |
| | B | 17,643 | 18,260 | 18,877 | 19,494 | 20,111 | 20,728 |
| | C | 36,552 | 39,811 | 43,069 | 46,328 | 49,587 | 52,846 |
| Bearskin Lake | A | 48,633 | 54,853 | 61,072 | 67,291 | 73,511 | 79,730 |
| | B | 2,827 | 4,080 | 5,332 | 6,585 | 7,837 | 9,090 |
| | C | 13,527 | 14,378 | 15,230 | 16,082 | 16,933 | 17,785 |
| Big Trout Lake | A | 50,774 | 53,321 | 55,868 | 58,415 | 60,962 | 63,509 |
| | B | 42,884 | 48,377 | 53,869 | 59,362 | 64,854 | 70,347 |
| | C | 49,039 | 51,814 | 54,588 | 57,363 | 60,137 | 62,912 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Biscotasing | A | 6,029 | 7,628 | 9,227 | 10,827 | 12,426 | 14,025 |
| | B | 30,430 | 36,534 | 42,638 | 48,742 | 54,846 | 60,950 |
| | C | 18,278 | 20,234 | 22,191 | 24,147 | 26,103 | 28,059 |
| Deer Lake | A | 914 | 1,319 | 1,723 | 2,128 | 2,533 | 2,938 |
| | B | 6,138 | 8,857 | 11,575 | 14,294 | 17,013 | 19,732 |
| | C | 42,731 | 48,188 | 53,646 | 59,103 | 64,561 | 70,018 |
| Fort Severn | A | 73,436 | 77,339 | 81,243 | 85,147 | 89,050 | 92,954 |
| | B | 23,398 | 27,913 | 32,427 | 36,942 | 41,456 | 45,970 |
| | C | 601 | 868 | 1,134 | 1,401 | 1,667 | 1,933 |
| Gull Bay | A | 13,144 | 14,040 | 14,937 | 15,833 | 16,729 | 17,625 |
| | B | 37,663 | 43,496 | 49,329 | 55,161 | 60,994 | 66,827 |
| | C | 12,446 | 14,364 | 16,282 | 18,200 | 20,118 | 22,036 |
| Hillsport | A | 48,445 | 53,272 | 58,100 | 62,928 | 67,756 | 72,583 |
| | B | 67,486 | 70,745 | 74,003 | 77,262 | 80,521 | 83,780 |
| Kasabonika Lake | A | 80,400 | 86,714 | 93,029 | 99,344 | 105,659 | 111,973 |
| | B | 1,770 | 2,554 | 3,338 | 4,122 | 4,906 | 5,690 |
| | C | 19,898 | 21,603 | 23,309 | 25,015 | 26,721 | 28,426 |
| Kingfisher Lake | A | 38,386 | 42,028 | 45,670 | 49,312 | 52,954 | 56,596 |
| | B | 42,751 | 46,607 | 50,463 | 54,319 | 58,175 | 62,031 |
| | C | 10,591 | 11,437 | 12,283 | 13,129 | 13,976 | 14,822 |
| Lansdowne House | A | 3,013 | 4,278 | 5,544 | 6,809 | 8,074 | 9,339 |
| | C | 23,372 | 30,170 | 36,967 | 43,765 | 50,562 | 57,360 |
| | D | 12,450 | 12,987 | 13,523 | 14,060 | 14,597 | 15,134 |
| Marten Falls | A | 81,172 | 84,779 | 88,385 | 91,991 | 95,597 | 99,204 |
| | B | 65,139 | 68,529 | 71,919 | 75,309 | 78,699 | 82,089 |
| | C | 52 | 75 | 98 | 121 | 144 | 167 |
| Oba | A | 26,736 | 32,103 | 37,470 | 42,836 | 48,203 | 53,570 |
| | B | 21,192 | 24,232 | 27,271 | 30,310 | 33,349 | 36,389 |
| | C | 6,137 | 6,388 | 6,638 | 6,889 | 7,139 | 7,390 |
| Sachigo Lake | A | 15,495 | 19,379 | 23,264 | 27,148 | 31,033 | 34,918 |
| | B | 26,041 | 28,538 | 31,035 | 33,532 | 36,029 | 38,526 |
| | C | 27,288 | 29,594 | 31,900 | 34,206 | 36,513 | 38,819 |
| Sandy Lake | G1 | 45,674 | 50,622 | 55,571 | 60,519 | 65,468 | 70,416 |
| | G2 | 27,413 | 31,370 | 35,327 | 39,284 | 43,241 | 47,198 |
| | G3 | 9,080 | 11,118 | 13,156 | 15,194 | 17,233 | 19,271 |
| | G4 | 4,798 | 9,597 | 14,395 | 19,193 | 23,991 | 28,790 |
| Sultan | A | 49,895 | 54,528 | 59,162 | 63,796 | 68,429 | 73,063 |
| | B | 48,289 | 51,299 | 54,310 | 57,321 | 60,331 | 63,342 |
| Wapekeka | A | 51,355 | 54,842 | 58,329 | 61,816 | 65,303 | 68,790 |
| | B | 13,216 | 15,075 | 16,933 | 18,792 | 20,650 | 22,508 |
| | C | 11,062 | 14,467 | 17,871 | 21,275 | 24,679 | 28,084 |
| Weagamow | A | 11,896 | 13,992 | 16,088 | 18,185 | 20,281 | 22,377 |
| | B | 5,515 | 7,958 | 10,401 | 12,844 | 15,286 | 17,729 |
| | C | 16,767 | 18,615 | 20,462 | 22,309 | 24,156 | 26,004 |

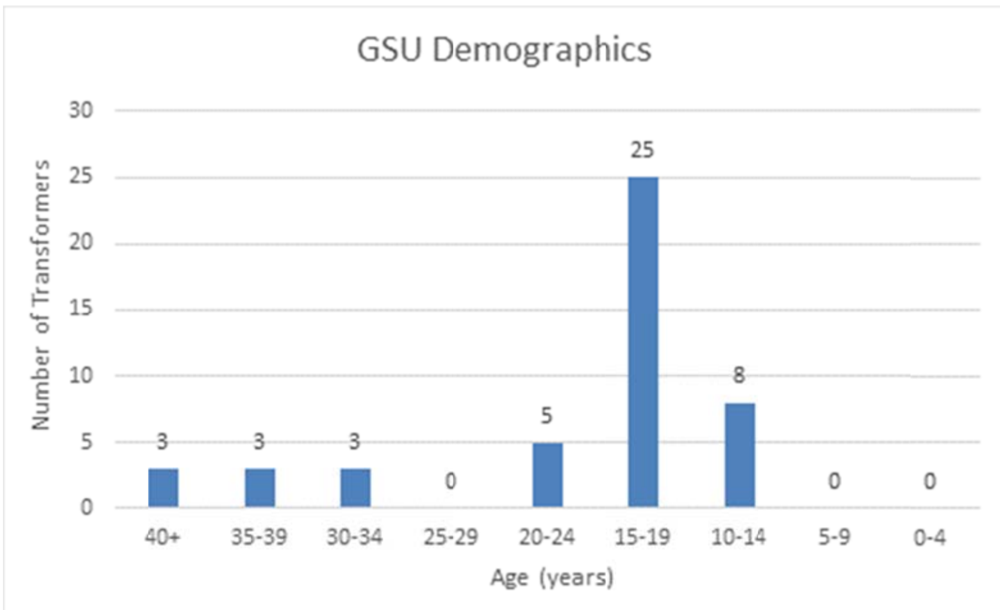
| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Webequie | G1 | 15,975 | 18,187 | 20,398 | 22,610 | 24,821 | 27,033 |
| | G2 | 34,462 | 39,786 | 45,111 | 50,436 | 55,761 | 61,085 |
| | G3 | 7,574 | 8,709 | 9,843 | 10,978 | 12,113 | 13,248 |

Many of these generators are already being managed based on the ACA results. In addition, a new generator for Biscotasing B will be procured in 2022, and a new generator for Gull Bay B will be procured and installed in 2021.

#### 3.2.3.2 Generator Step-up Transformers

The age demographics for the in-service GSUs owned by Remotes are shown in Figure 3-7.

Figure 3-7: Age Demographics for GSUs




The ACA results of the in-service GSUs, determined using age-based health indices, are shown in Table 3-8.

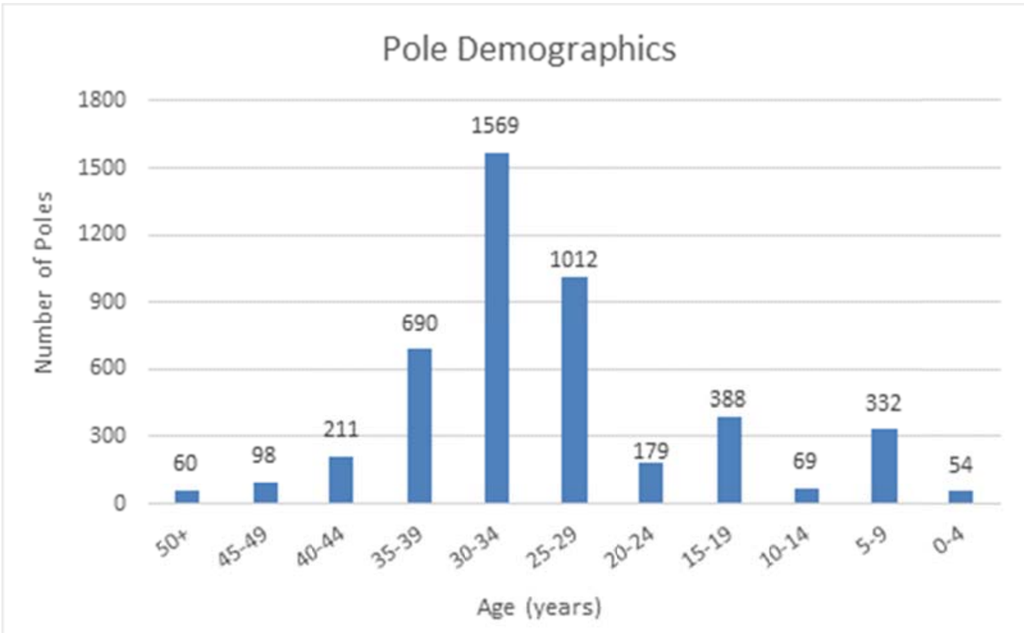
Table 3-8: Summary of the ACA for GSUs

| VP | P | F | G | VG |
|---|---|---|---|---|
| 0 | 0 | 3 | 11 | 33 |

### 3.2.3.3 Poles

Remotes owns 4,662 poles, a large portion of which are between 25 and 35 years old. The average pole age on the system is 28 years. Figure 3-8 presents the pole age demographics.

Figure 3-8: Age Demographics for Poles




Remotes' ACA for poles considers three categories:

- Very Poor – emergency replacement
- Poor – replace within five years
- Good – no replacement over next five years

An inspection was done on 3,977 of Remotes' wood poles in 2016 in every community. The inspections did not include the line from Armstrong to Collins, which is too expensive to patrol. The community of Collins does not have road or plane access and must be reached by train. The poles on this line are, therefore, replaced only on emergency response. The inspection included the following:

1. A hammer test is performed on each pole and values recorded as follows:
    a. OK (no action required)
    b. Hollow
2. A prodding test for surface rot or deterioration is performed on each pole and values recorded as follows:
    a. Light
    b. Medium
    c. Severe
3. A visual (condition) test is performed and values rated follows:
    a. Like New

b. Good
c. Fair
d. Poor
e. Very Poor

Other visual defects, for example woodpecker damage, are assessed as part of the inspection.

Table 3-9 summarizes the results of the ACA for poles. Over the next five years, Remotes is planning to replace 115 poles identified to be in poor condition. Additional pole replacements are typically required to maintain clearances.

Table 3-9: Summary of the ACA for Poles

| Emergency | Replace Within 5 Years | No Replacement Within 5 Years |
|---|---|---|
| 0 | 115 | 3,871 |

Based on the age demographics, a significant number of poles will be approaching end-of-life around the year 2040. Actual end-of-life assessment will be made based on condition. Remotes has kept this in mind for its long-term planning, but does not warrant any additional investment over the short term.

### 3.2.3.4 Distribution Transformers

Remotes currently owns about 1,138 distribution transformers. Figure 3-9 shows the age demographics for Remotes' distribution transformers and Table 3-10 presents the condition summary based on the age demographics.

Figure 3-9: Age Demographics for Distribution Transformers

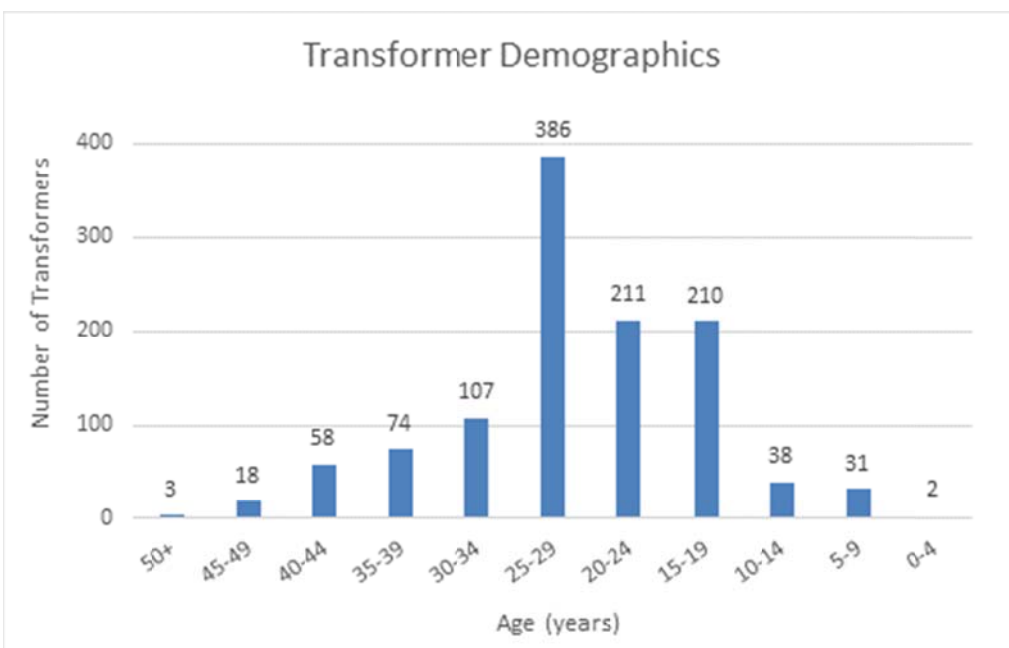


Table 3-10: Summary of the ACA Results for Distribution Transformers

| VP | P | F | G | VG |
|---|---|---|---|---|
| 79 | 181 | 597 | 248 | 33 |

## 3.2.4 System Utilization (5.3.2d)

As specific communities expand, Remotes' equipment is electrically loaded and stressed to higher levels. When loading and stresses exceed the equipment design capability and nameplate ratings, the equipment must be replaced with higher capacity equipment to ensure safety and reliability of supply. Table 3-11 illustrates the peak load in each community over the past four years, along with the community's station capacity and the connection limit (85% of the station capacity).

Table 3-11: Peak Load and Station Rating by Community

| Community | Station Rating | Connection Limit | Peak Load (kW) 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|
| **Armstrong** | 1450 | 1233 | 1021 | 1035 | 974 | 980 |
| **Bearskin Lake** | 1000 | 850 | 609 | 594 | 589 | 640 |
| **Big Trout Lake** | 1600 | 1360 | 1322 | 1395 | 1260 | 1277 |
| **Biscotasing** | 156 | N/A* | 145 | 170 | 166 | 146 |
| **Deer Lake** | 1795 | 1526 | 1357 | 1230 | 1220 | 1230 |
| **Fort Severn** | 1000 | 850 | 574 | 554 | 650 | 589 |
| **Gull Bay** | 430 | 366 | 334 | 316 | 288 | 325 |
| **Hillsport** | 125 | N/A* | 81 | 82 | 91 | 94 |
| **Kasabonika Lake** | 1600 | 1360 | 990 | 972 | 1106 | 1018 |
| **Kingfisher Lake** | 650 | 553 | 623 | 649 | 605 | 614 |
| **Lansdowne House** | 875 | 744 | 499 | 577 | 535 | 451 |
| **Marten Falls** | 650 | 553 | 489 | 493 | 494 | 475 |
| **Oba** | 120 | N/A* | 79 | 76 | 69 | 64 |
| **Sachigo Lake** | 1000 | 850 | 718 | 672 | 701 | 677 |
| **Sandy Lake** | 3050 | 2593 | 2576 | 2515 | 2370 | 2528 |
| **Sultan** | 150 | N/A* | 186 | 167 | 154 | 120 |
| **Wapekeka** | 865 | 735 | 643 | 628 | 621 | 595 |
| **Weagamow** | 1300 | 1105 | 1096 | 1025 | 966 | 979 |
| **Webequie** | 1000 | 850 | 625 | 615 | 647 | 633 |

**no load growth*

In communities where there is no load growth, the connection limit is not relevant planning criteria. These communities have a high number of seasonal customers and the peak loads often occur on holiday weekends.

Remotes existing feeder conductors have ample capacity for the loads in the communities. Most communities are served by 25 kV feeders with the remainder of smaller communities served by 4.16 kV systems. Given the small load sizes (below 3MW), the feeder conductors can carry loads several times larger than the current community peak load.

The generation station transformers are sized appropriately for the diesel generation station maximum load. Accordingly, the transformers are changed as part of the generation station upgrade process. The funding for the First Nation communities' generation station upgrades, which includes the replacement of the station transformers, is provided by the Federal government.

## 3.3 Asset Lifecycle Optimization and Risk Management (5.3.3)

This section presents Remotes' asset lifecycle optimization and risk management policies and practices.

### 3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

Remotes' assets are managed based on a lifecycle management approach, which considers and balances asset performance, costs and associated risks during the asset service life to achieve asset optimization. Remotes investigated the relationship between capital spending and system O&M costs. Regardless of the capital spending, generator maintenance is required every 2,500 engine-hours. Due to the associated flight and fuel costs of this maintenance, there is no reduction to system O&M costs from capital investment.

#### 3.3.1.1 Asset Replacement and Refurbishment Policies

Replacements and refurbishments of distribution assets include planned improvements and component replacements required to maintain the operation of distribution lines and associated equipment. They consist mainly of betterment projects and system upgrades, based on the asset age demographics and inspection results on asset condition in the community. The betterments include pole replacements, conductor restringing, and pole re-alignments.

Diesel generators are maintained as per manufacturer-published recommendations including complete overhauls after specified hours. The decision to replace or refurbish a generator is based on economics. Medium-speed (1800 rpm) units are rebuilt after 20,000 engine-hours, while low-speed (1200 rpm) units are overhauled between 32,000 and 40,000 engine-hours. After two overhauls, it is no longer economical to refurbish the generator as the life has been extended twice, parts may be obsolete and to improve fuel efficiency. Therefore, medium-speed generators are replaced after 60,000 engine-hours and low-speed generators are replaced between 96,000 and 120,000 engine-hours. Some units may be identified for earlier replacement subject to specific issues and asset condition discovered during its lifecycle. Replacement may be advanced or lengthened accordingly. A diesel generator replacement includes replacement of the auxiliary equipment and, often, replacement of the GSUs and breakers based on an assessment of their age, condition, and available capacity.

#### 3.3.1.2 Maintenance Policies, Planning Criteria and Assumptions

Remotes' maintenance programs are defined for each asset listed below. In addition to the asset-specific programs, Remotes performs routine maintenance and inspections of various aspects and elements of the generating station.

**Engines and Generators**

Maintenance of engines and generators can be divided into planned and unplanned maintenance.

Planned maintenance of diesel generating units prevents premature equipment and system failures and contributes to service reliability. It includes all work performed on the diesel engine and associated generator in accordance with standard maintenance procedures as prescribed by the engine manufacturer. Intensive maintenance procedures are scheduled based on engine hours and vary from year to year. Inspections on engines are done every 5,000 hours.

Unplanned maintenance includes maintenance and repair of diesel generating units in response to trouble reports and equipment/component failures. This work is required to keep the station generating units available and operating to satisfy the rated station capacity required to meet community load. The program may identify the need for repairs/component replacement that would not be accomplished in the planned maintenance program.

**Tank Farms**

Planned maintenance of tank farms and associated equipment includes regular inspections of all bulk fuel storage tanks, transfer pumps, control circuitry, piping and valves in the tank farm and the fuel delivery kiosk. This work helps prevent premature failures and ensures the tank farm remains in working condition throughout its entire asset life. Tank farm inspections occur at all 19 stations. A review of outstanding fuel compliance audit findings is carried out to develop a long-term action plan. Corrective actions will be undertaken on a planned basis to address significant tank and fuel system defects as identified.

Unplanned maintenance of tank farms is a response to tank farm and fuel system problems and includes repair work required to keep the generating station fuel offload, bulk storage tanks and fuel transfer equipment in standard operating condition.

Remotes audits its fuel storage, fuel systems, fuel handling and record keeping in each community for compliance with federal and provincial regulations on a four-year cycle. Regulations related to fuel systems, storage and handling and record keeping are reviewed regularly and changes are incorporated into compliance reviews/audits. The reviews encompass the entirety of the fuel systems and identify opportunities for improvement, required testing or minor modifications, and areas of non-conformance. The audits look for items such as training, pipe corrosion, protection of pipes from vehicles, fire safety, and supports for above-ground tanks. When areas of non-compliance are noted, capital improvements to meet regulatory standards are scheduled based on condition of the assets and severity of the defect. In 2016, Remotes invited representatives of the provincial regulatory authority, the Technical Standards and Safety Authority, to participate in these compliance review/audits to improve the quality of the audit process and to improve its understanding of the regulatory requirements.

**Facilities**

Maintenance of facilities includes minor civil repair work required to maintain 19 generating station buildings, 14 staff houses, the Thunder Bay service center, fences, yards/sites which includes annual inspections and annual sampling of water facilities for all staff houses and generating stations. Planned maintenance of facilities ensures they may be used for projected asset life without the need for major refurbishments.

**REG Maintenance**

REG maintenance includes inspection and repair of equipment at REG facilities (water/wind powered) such as generating units and associated equipment. Maintenance is required to keep these stations and associated facilities in a standard operating condition. This program involves primarily planned inspection and maintenance of the hydro-electric stations located at Deer Lake and Sultan. The yearly maintenance involves hydraulic system maintenance, gear box maintenance, generator maintenance, switchgear and control maintenance, and turbine checks.

Unplanned maintenance may also be performed in response to issues identified during routine station operation. This can include, but is not limited to, the repairs and modifications of the water intake and outflow facilities, the generator units and auxiliary equipment, generator gears, communications equipment, and the station building/site.

**Auxiliary Systems**

Maintenance work on Generating Station auxiliary equipment is required to keep them in standard operating condition. The work is performed based on the results of diagnostic tests such as coolant sample analysis, along with normal cyclical maintenance, as part of an annual inspection or along with a major engine maintenance or overhaul procedure. Auxiliary equipment includes secondary heating, primary cooling, ventilation, overhead crane inspections, electrical, control and fire protection systems. Auxiliary systems maintenance includes, the main breaker cabinet, the station PLC, secondary heating, primary cooling, ventilation, pump controls, overhead crane inspections, station air compressors, DC batteries, station service electrical equipment and fire protection systems and all fuel system equipment and controls within the station.

**GSUs**

Remotes does not currently maintain its GSUs but is investigating which maintenance activities will be beneficial to manage the risk of these assets.

**Distribution Assets**

Maintenance on distribution assets is intended to ensure that the overall reliability of the distribution systems is maintained and improved, customer commitments are met, and all legislative and regulatory requirements are met. Data collected over past years identifies the required minor maintenance tasks in the communities.

Planned maintenance includes corrective and preventative line maintenance. The Distribution System Code requires that all local distribution companies patrol their distribution lines on a five-year cycle, to identify structural problems, damaged equipment and components that may cause a power interruption, as well as any hazards such as leaning poles, damaged equipment enclosures and vandalism. Preventative maintenance includes maintenance that is primarily cyclical in nature, including maintenance of equipment (load brake switches, electronic switches), as a means of reducing unplanned outages.

### 3.3.2 Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

The assets that make up the two major asset categories for generation and distribution are grouped into 15 different asset classes. These asset classes are further allocated to one of three asset priority categories: Priority 1 (P1); Priority 2 (P2); and Priority 3 (P3). The priorities reflect the criticality of the asset class to the Remotes' system, and include consideration of factors such as: public safety and employee health & safety; the importance of the asset to the sustained operation and reliability of the Remotes' system; electricity security; new equipment procurement lead times; regulatory and environmental requirements; and economics.

P1 assets represent the highest priority assets and are of high value and high risk to the business, receiving proportionally more of the total sustainment program funds. P2 assets are next in priority and, although they include high-risk assets, these generally require comparatively moderate program funds. Finally, P3 assets are lowest in priority with low program funds and lower risk to the business.

The allocation of the 15 asset classes into the three asset priority categories is indicated in Table 3-12. Capital expenditures identified in this DSP are selected and prioritized per this priority.

Table 3-12: Prioritization of Assets

| | **P1: High Priority** | **P2: Moderate Priority** | **P3: Low Priority** |
|---|---|---|---|
| **Generation** | • Generation<br>• Station Transformers<br>• Fuel System & Fuel Inventory<br>• Land Assessment & Remediation | • Generation Circuit Breakers<br>• Protection & Control<br>• Oil Containment | • Generation Station Service (AC/DC) |
| **Distribution** | • Overhead Line Sections<br>• Wood Poles<br>• Distribution Transformers<br>• Right of Way Vegetation | • Switches & Fuses<br>• Distribution: Operating Transformer Spares | • Meters |

The continued performance of these assets is managed through capital investment and maintenance programs discussed in Section 3.3.1.2. Most communities have three diesel generators, rated for different capacities to optimize fuel efficiency. In case of a generator outage, the other generators can be used to mitigate the effects of the next contingency if a lengthy repair is required. Remotes keeps a spare transformer at each community to mitigate the impact of an outage. If a transformer fails, the community experiences a power interruption until the power can be switched to the spare – typically four hours.

# 4 Capital Expenditure Plan (5.4)

This section provides information on Remotes' capital investment program – derived from its asset management process – over the forecast period.

## 4.1 Summary (5.4.1)

### 4.1.1 Ability to Connect New Load (5.4.1a)

With population changes and more intensive use of electricity in remote communities, the overall number of new load connections for Remotes has increased. Due to the size of the communities served by Remotes, small changes in the electricity usage can have a large impact on the ability to connect new load.

Over the forecast period, capacity upgrades are planned in six of Remotes' diesel generation stations; Big Trout Lake, Deer Lake or Kasabonika, Fort Severn, Sandy Lake, Wapekeka and Weagamow. The peak load in these communities will surpass, or will be close to surpassing, 85% of the station rating in the next five years.

### 4.1.2 Capital Expenditures over the Forecast Period (5.4.1b)

Figure 4-1 depicts the net capital expenditures planned for each year of the forecast period. The investments are divided into system access, distribution system renewal, distribution system service, generation system renewal, generation system service, and general plant. There are planned expenditures in the system access category over the forecast period, but these projects and programs are 100% recoverable and, therefore, there is no forecast net spending. There are no planned expenditures that fall into the distribution system service category over the forecast period.

Figure 4-1: Net Capital Expenditure Forecast by Investment Category

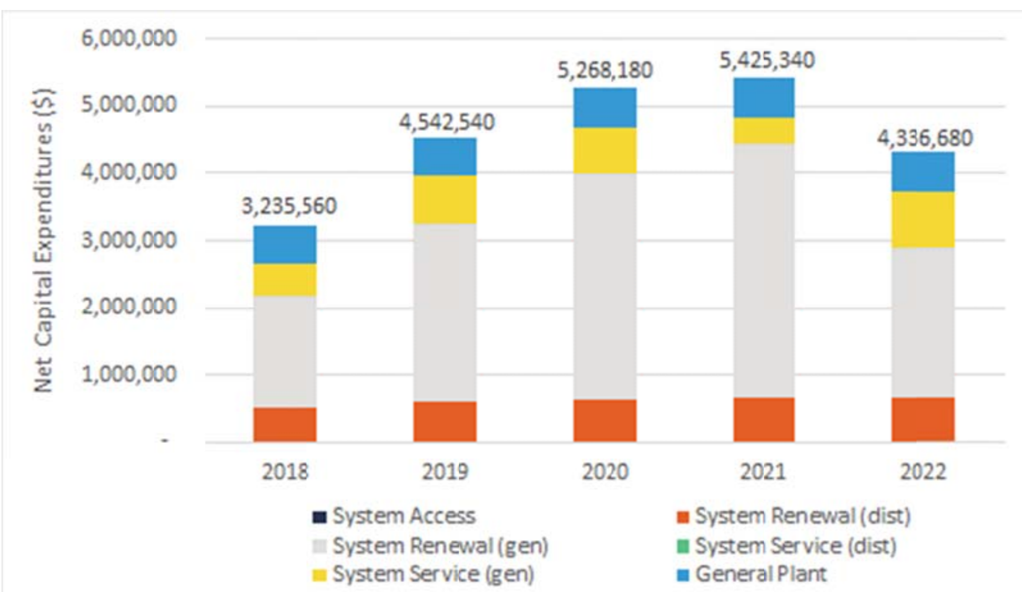


Table 4-1 presents the breakdown of capital expenditures on the distribution system, which includes system access and system renewal investments.

Table 4-1: Capital Expenditure Forecast by Investment Category - Distribution

| Investment Categories | Forecast ($) | | | | |
|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 |
| **System Access (gross)** | 912,000 | 1,065,000 | 1,121,000 | 1,143,000 | 1,166,000 |
| Contributions & Removals | (912,000) | (1,065,000) | (1,121,000) | (1,143,000) | (1,166,000) |
| Net | 0 | 0 | 0 | 0 | 0 |
| **System Renewal (gross)** | 772,000 | 899,000 | 947,000 | 965,000 | 983,000 |
| Contributions & Removals | (250,240) | (290,360) | (304,120) | (311,160) | (313,320) |
| Net | 521,760 | 608,640 | 642,880 | 653,840 | 669,680 |
| **System Service** | 0 | 0 | 0 | 0 | 0 |
| **Total Distribution (gross)** | **1,684,000** | **1,964,000** | **2,068,000** | **2,108,000** | **2,149,000** |
| Contributions & Removals | **(1,162,240)** | **(1,355,360)** | **(1,425,120)** | **(1,454,160)** | **(1,479,320)** |
| Net | **521,760** | **608,640** | **642,880** | **653,840** | **669,680** |

Table 4-2 presents the breakdown of capital expenditures on the generation system, which includes system renewal and system service investments.

Table 4-2: Capital Expenditure Forecast by Investment Category - Generation

| Investment Category | Forecast ($) | | | | |
|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 |
| **System Renewal (gross)** | 1,788,000 | 2,847,000 | 3,582,000 | 3,994,000 | 2,426,000 |
| Contributions & Removals | (144,200) | (211,100) | (212,700) | (203,500 | (205,000) |
| Net | 1,643,800 | 2,635,900 | 3,369,300 | 3,790,500 | 2,221,000 |
| **System Service (gross)** | 5,853,000 | 6,852,000 | 6,392,000 | 5,412,000 | 5,810,000 |
| Contributions & Removals | (5,348,000) | (6,126,000) | (5,717,000) | (5,021,000) | (4,962,000) |
| Net | 505,000 | 726,000 | 675,000 | 391,000 | 848,000 |
| **Total Generation** | **7,641,000** | **9,699,000** | **9,974,000** | **9,406,000** | **8,236,000** |
| Contributions & Removals | **(5,492,200)** | **(6,337,100)** | **(5,929,700)** | **(5,224,500)** | **(5,167,000)** |
| Net | **2,148,800** | **3,361,900** | **4,044,300** | **4,181,500** | **3,069,000** |

Table 4-3 presents the breakdown of capital expenditures on the general plant investments.

Table 4-3: Capital Expenditure Forecast - General Plant

| Investment Category | Forecast | | | | |
|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 |
| **General Plant (gross)** | 565,000 | 572,000 | 581,000 | 590,000 | 598,000 |
| Contributions & Removals | 0 | 0 | 0 | 0 | 0 |
| Net | 565,000 | 572,000 | 581,000 | 590,000 | 598,000 |

## 4.1.3 D

The following information provides a brief outline of the outputs of the asset management and capital expenditure planning process that have affected capital expenditures in the four investment categories.

### 4.1.3.1

System access investments include service cancellations, fixed price layouts, new customer connections, and service upgrades, all of which are initiated by customers. Gross expenditures are forecast based on historical levels and the actual spending each year depends on the number and nature of the customer requests received. System access investments over the forecast period are all 100% recoverable from customers and, as such, Remotes has not forecast net expenditures in this category.

### 4.1.3.2

Investments in the system renewal category comprise 73% of the forecast period net capital expenditures. These investments are driven by assets reaching the end of their service life as determined by the ACA, and include meter replacements, damage claims and storm damage restoration, pole replacements, system upgrades, and betterments. For the generation assets, system renewal work includes engine replacements, engine overhauls, diesel plant civil improvements, and fuel tank replacements.

### 4.1.3.3

System service investments includes solely investments related to generation equipment, which account for approximately 14% of the net capital expenditures over the forecast period. This work, however, constitutes a large part of Remotes' gross capital cost – equivalent to about 52%. This discrepancy is attributable to the fact that bulk of the work that falls into this category entails customer-requested generation project work that is fully funded by INAC. Projects comprising this category for the forecast period include generation station upgrades in Big Trout Lake, Deer Lake or Kasabonika (to be reassessed close to 2022), Fort Severn, Sandy Lake, Wapekeka, and Weagamow. Other investments in this category include generation station SCADA and PLC replacements, with upgrades planned in Weagamow and Kingfisher in 2018.

#### 4.1.3.4

Investments in the general plant category account for approximately 12% of the net capital expenditures and include housing improvements and other civil projects based on the building assessment (see Appendix H: Hydro One Remotes Roof Assessment Report) and investments into minor fixed assets.

### 4.1.4 L

The budgeted costs of projects and programs above the materiality threshold ($283,000) are presented below for each investment category.

#### 4.1.4.1

The only material program under the category of system access is new customer connections & service upgrades. The planned gross cost for this project can be seen in the table below, but the costs are 100% recoverable.

Table 4-4: Material System Access Projects over the Forecast Period

| Project | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| New Customer Connections & Service Upgrades | 658,000 | 768,000 | 809,000 | 824,000 | 840,000 |
| Contributions | (658,000) | (768,000) | (809,000) | (824,000) | (840,000) |
| Net | 0 | 0 | 0 | 0 | 0 |

The year-over-year increase in the forecasted expenditures is driven by potential expansion of the service territory.

#### 4.1.4.2 System Renewal

##### 4.1.4.2.1 Distribution

Distribution system improvements are the only material project on the distribution side in the system renewal category. The forecast expenditures are illustrated in Table 4-5.

Table 4-5: Material Distribution System Renewal Projects over the Forecast Period

| Project | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| Distribution System Improvements | 636,000 | 743,000 | 783,000 | 797,000 | 813,000 |
| Contributions & Removals | (216,320) | (253,160) | (265,960) | (271,640) | (273,560) |
| Net | 419,680 | 489,840 | 517,040 | 525,360 | 539,440 |

This work varies year to year based on the size, nature, and volume of joint use activity and asset degradation. The yearly increase can be accounted for by the expansion of the service territory.

#### 4.1.4.2.2 Generation

Engine replacements and engine overhauls make up a substantial part of system renewal investments. The gross and net expenditures for replacements and overhauls are shown in Table 4-6.

Table 4-6: Engine Replacements and Overhauls over the Forecast Period

| Project | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| Engine Replacements | - | - | - | 1,317,000 | 1,318,000 |
| Big Trout Lake A Replacement | 767,000 | 1,423,000 | - | - | - |
| Big Trout Lake B Replacement | - | - | 1,425,000 | - | - |
| Removals (10%) | (76,700) | (142,300) | (142,500) | (131,700) | (131,800) |
| Net | 690,300 | 1,280,700 | 1,282,500 | 1,185,300 | 1,186,200 |
| Engine Overhauls | 675,000 | 688,000 | 702,000 | 718,000 | 732,000 |
| Removals (10%) | (67,500) | (68,800) | (70,200) | (71,800) | (73,200) |
| Net | 607,500 | 619,200 | 631,800 | 646,200 | 658,800 |
| **Total (net)** | **1,297,800** | **1,899,900** | **1,914,300** | **1,831,500** | **1,845,000** |

Other material projects in this category include tank replacements and diesel plant civil improvements. The expenditures are shown in Table 4-7.

Table 4-7: Fuel Tank Replacements and Diesel Plant Civil Improvements

| Project | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| Sultan Bulk Tank Farm | - | - | - | 274,000 | - |
| Armstrong Day Tank | - | - | 438,000 | - | - |
| Big Trout Bulk Tanks & Day Tanks | - | - | 657,000 | 1,317,000 | - |
| Oba Bulk Tank | - | 383,000 | - | - | - |
| Diesel Plant Civil Improvements | 346,000 | 353,000 | 360,000 | 368,000 | 376,000 |
| **Total** | **346,000** | **736,000** | **1,455,000** | **1,959,000** | **376,000** |

### 4.1.4.3 System Service

#### 4.1.4.3.1 Distribution

There are currently no planned projects on the distribution side of the system service category.

#### 4.1.4.3.2 Generation

Table 4-8 shows the forecast generation projects in the system service category that meet the materiality threshold. Most of them are generation station upgrades. In addition to capacity upgrades in Big Trout Lake and Wapekeka, an integration of controls for these two generation stations is planned. All the station upgrades are (100% recoverable from INAC. Other generation projects in the system service category include controls and SCADA upgrades at the generating stations.

Table 4-8: Material Generation System Service Projects over the Forecast Period

| Project | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| Generator Upgrades | | | | | |
| Big Trout Lake - Wapekeka Upgrade & Connection | 2,149,000 | 3,252,000 | 1,364,000 | - | - |
| Deer Lake or Kasabonika | - | - | - | 1,364,000 | 4,962,000 |
| Fort Severn | - | - | 3,042,000 | 3,657,000 | - |
| Sandy Lake | 367,000 | 881,000 | 1,311,000 | - | - |
| Weagamow | 2,832,000 | 1,993,000 | - | - | - |
| Contributions | (5,348,000) | (6,126,000) | (5,717,000) | (5,021,000) | (4,962,000) |
| Net | 0 | 0 | 0 | 0 | 0 |
| Controls/SCADA Upgrades | | | | | |
| Sandy Lake & Biscotasing - Bulk Tank Platform & Controls | - | - | - | - | 495,000 |
| SCADA & PLC Replacements & High-Speed Internet | 505,000 | 726,000 | 675,000 | 391,000 | 353,000 |
| **Total (net)** | **505,000** | **726,000** | **675,000** | **391,000** | **848,000** |

### 4.1.4.4 General Plant

Table 4-9 lists the planned expenditures in the general plant category over the forecast period. Programs in this category include housing improvements, storage buildings, miscellaneous civil projects, and minor fixed assets. None of these programs exceed the materiality threshold.

Table 4-9: General Plant Spending over the Forecast Period

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| General Plant | 565,000 | 572,000 | 581,000 | 590,000 | 598,000 |

### 4.1.5 Information pertaining to the Regional Planning Process (5.4.1e)

The 2014 draft Remote Community Connection Plan is a business case which informed a July 29, 2016, Order-in-Council from the Provincial Government. This order confirms the intention for the project to connect 16 remote communities to the transmission system. Nine of these communities are presently served by Remotes and at least two are expected to be served by Remotes in the future. While this will not affect investments in the communities over the five-year period of this DSP, it has affected the investments INAC makes in generation assets, and it is expected that the construction activities of this new transmission line will affect Remotes planning considerations over the medium-to-long term. The order from the Minister of Energy is included as Appendix C: Order-in-Council from the Minister of Energy.

Since the Remote Community Connection Plan is still in its draft form, the connection dates for the communities served by Remotes are not firmly established at this time. Furthermore, there is the possibility of retaining Remotes' diesel generation fleet for community electricity supply backup, as per the diesel backup study (see Section 2.2.1.3.4). Based on the need to continue to provide customers with a reliable supply of electricity in the near term and the possibility of retaining the generator fleet to serve as backup power supply, Remotes' generator replacement and overhaul programs have not been affected by the Regional Planning Process.

Regional electricity infrastructure requirements have been accounted for in Remotes' generator upgrade plan. In anticipation of the new transmission lines reaching the communities of Big Trout Lake (Kitchenuhmaykoosib Inninuwug) and Wapekeka, a new distribution line is being constructed as an integrated, cost-effective approach to increase the capacity of both communities, as well as improving the robustness of the electricity supply. The new distribution line will be required to connect the communities to the new transmission line. The peak load in Weagamow is forecast to reach the connection limit in 2019; therefore, Remotes intends to proceed with the generator upgrade in this community. The project plan accounts for the anticipated future connection of this community and tank storage upgrades have been foregone as a more near-term approach due to the long-term uncertainties. The peak load in Sandy Lake is forecast to reach the connection limit in 2018, so the generator upgrade project in Sandy Lake will also proceed.

### 4.1.6 Customer Engagement Activities (5.4.1f)

Remotes listens to its customers and, in First Nations communities, works closely with Band Councils to help them meet community electricity needs and preferences. Remotes regularly communicates and meets with their customers throughout the year. The focus of communication efforts is with First Nation communities that comprise approximately 90% of the customer base. Each community has a direct contact with Remotes. Communication takes place in many forms including email, phone, letter, conference call, or face-to-face meetings. Remotes' customers have asked for more face-to-face meetings, so Remotes has increased the frequency that it visits the communities and has started including its customer service staff in community meetings.

Funding arrangements with INAC also require Remotes to meet with INAC and local First Nations to plan capital projects. Since 2009, the Director of Remotes has had specific performance targets to meet face-to–face at least eight times per year with First Nation Band Councils or Tribal Councils to discuss areas of mutual concerns and to maintain open lines of communication. Other staff also meet with First Nation Band Councils or Tribal Councils regularly to discuss topics such as:

**<u>All Communities – Normal Activities & Communication</u>**

- Connections, collections, work in community
- Customer renewables
- Insurance
- Snowplowing
- Gravel
- Planned housing
- Winter road tolls
- Equipment rental
- Temporary labour
- Charity and sponsorship
- Meter reading
- Operator contracts
- Disconnections
- Winter road conditions
- Third party staff house use
- Environmental - site
- Forestry line clearing
- Community emergencies/disruptions
- Public Safety
- Community energy overview, load, peak, assets
- Energy forecast and housing, community development

**<u>Communities Not Served by Remotes</u>**

- Our services, asset assessment and condition, transferring to Hydro One Networks Inc.
- Grid line development

**<u>Communities No Longer Served by Remotes</u>**

- Remediation

**<u>Collins/Namaygoosisagagun First Nation (Armstrong Area)</u>**

- Trouble response

**Whitesand First Nation (Armstrong Area)**

- First Nation biomass renewable project (including IESO and CIA package), technical and operational meetings
- Distribution expansion and ownership
- Reindeer rates
- Load growth and peak
- Emissions

**Bearskin**

- First Nation fuel purchase – winter road
- Generation upgrades
- Heat traces
- Remediation of old site (bio cell)
- Reliability
- Renewables
- Third party financing

**Big Trout/Kitchenuhmaykoosib Inninuwug**

- First Nation fuel purchase – winter road
- Connection restrictions
- Proposed line between Big Trout Lake and Wapekeka
- Long term payment plan
- Leaning poles
- Community sub-contractor concerns
- Fuel truck operations – kiosk spill
- Windmill production
- Urgent fuel needs
- Outage - lengthy
- University research project
- Loaned fuel
- Arena usage
- Fuel wagon delivery
- Forestry concerns, tree replanting

**Deer Lake**

- Generation upgrades
- School solar
- Shoulder Blade falls hydel production and operation
- Community restrictions
- Third party financing
- Long term payment plan
- Housing connections – urgent
- Conservation and demand management
- Funding support
- Long term operating agreement – Shoulder Blade
- Potential fuel farm

**Fort Severn**

- First Nation fuel purchase – winter road and barge
- Community solar project – large scale installation
- Renewable projects – roof mounted
- Letters of funding support
- Secondary heat – water treatment plant
- Fuel quality
- Generation upgrade
- Generation trouble response
- Load restrictions
- New school
- Wind turbine – old and proposed
- Old Hydro house – sale
- Renewable study support
- Conservation and demand management
- Site expansion

**Gull Bay**

- Consumption
- Solar – micro grid project (OPG)
- Hydroelectric discussion
- Emissions
- Rates
- Rate relief
- Land permits
- Future diesel upgrade

**Kasabonika**

- Generation upgrades
- Damage claim
- Connection restrictions
- Fibre
- Renewable research
- Petrokas tank farm upgrades
- Fuel contract award
- Gravel misuse
- Wind turbine production
- Christmas lights
- Petrokas operation and maintenance
- Noise complaint – wind
- New store

**Kingfisher**

- Generation upgrades
- Connection restrictions
- Site environmental
- Kingfisher preferred fuel suppliers

- Solar installation
- Yard expansion
- Surplus equipment sale
- Recycling oil

**Lansdowne**

- Generation upgrades
- Connection restrictions
- Community centre load impacts

**Marten Falls**

- Long term arrears
- Connection restrictions
- Outages
- Account set up
- Fuel sale – third party
- Winter road delivery and logistics

**Sachigo**

- First Nation fuel purchase – winter road
- Generation upgrades
- Flights to Sachigo
- First Nation pipe leak
- Third party financing letter
- First Nation tank farm design and operation
- Timing of collections trip

**Sandy Lake**

- First Nation fuel purchase – winter road
- Low fuel levels
- Financing letters of support
- First Nation tank farm upgrades and operations
- Duck River Hydroelectric development
- Old Hydro house
- Loaned fuel

**Wapekeka**

- Generation upgrades
- Connection restrictions
- Proposed line between Big Trout Lake and Wapekeka
- Technical diesel generation station study
- School fire and replacement
- Long term payment plan
- Fawn River Hydroelectric
- Wapekeka Solar
- Community fuel deliveries

**Weagamow/North Caribou First Nation**

- Generation upgrades
- Connections restrictions
- Proposed solar project
- Streetlight retrofit
- Conservation and demand management
- Temporary power agreement and operation
- Emergency response
- Site environmental
- Christmas lights
- Trailer extension
- House permit
- Certificate of Approval and Environmental Compliance Approval ownership
- Tank farm project
- Road development
- Site expansion

**Webequie**

- Remediation of old site
- Long term payments and arrears
- Public safety
- Solar connection
- Sale of old Hydro house
- Airport operations

**Other First Nation Partners (Tribal Councils)**

These partners include Matawa First Nations Management, Keewaytinook Okimakanak, Shibogama First Nations Council, Nishnawbe Aski Nation, Windigo First Nations Council, and Independent First Nations Alliance.

- Project or issues supporting specific communities above.

### 4.1.7 System Development over the Forecast Period (5.4.1g)

System development over the forecast period is presented with respect to load and customer growth, smart grid, and REG accommodation.

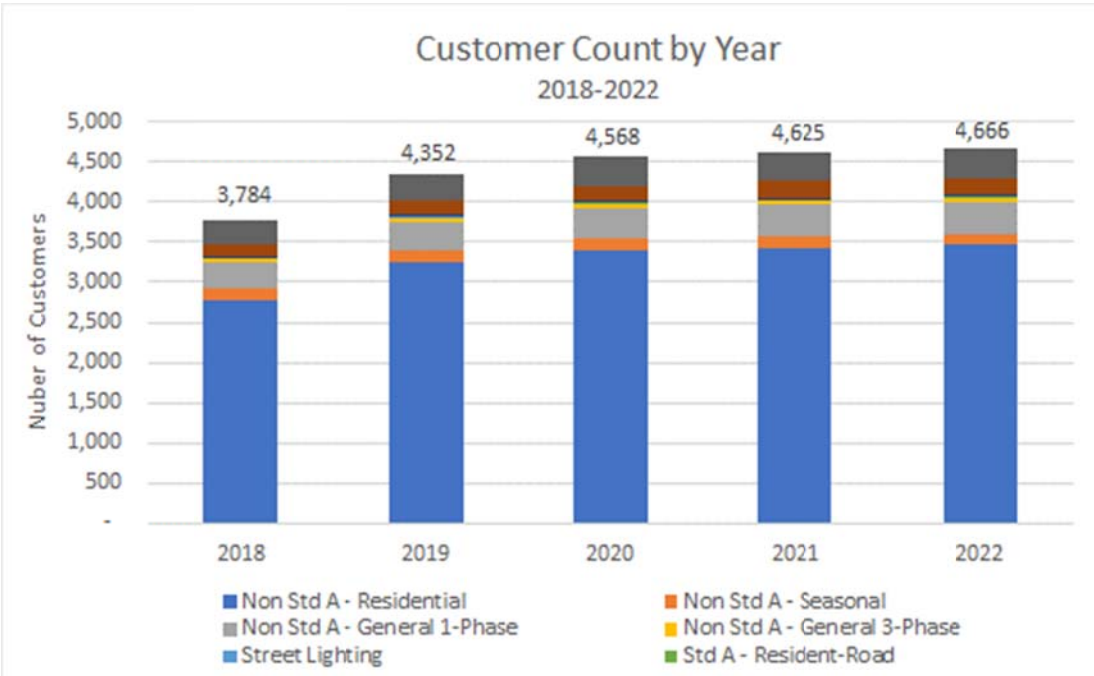
#### 4.1.7.1 Load and Customer Growth

Remotes' service area is expected to expand to include three new communities during the forecast period. One of these, Cat Lake, is already connected to the Hydro One Networks Inc. transmission system in northwestern Ontario; therefore, Remotes will only be responsible for power distribution in this community. This transfer is planned for 2018, is contingent upon an agreement with the community, and will result in a customer increase of 111. Watay Power is planning to build a distribution line to the community of Pikangikum in 2017 to 2018, in advance of other community connections. If the line is built, then Remotes will operate the distribution assets in the community, with distribution lines servicing about

2,300 people and 532 customers. Remotes assessed the generation and distribution assets in Wunnumin Lake. With limited capital investments, Remotes could safely and reliably operate the distribution and generation assets in the community. A transfer of service to Remotes is planned for 2020, prior to the community's connection to the grid, adding 176 new customers to Remotes service territory.

Remotes' total customer growth is shown in Figure 4-2. The annual load growth in Remotes' existing communities is forecasted to be around 3.5%.

Figure 4-2: Remotes' Customer Growth over the Forecast Period




Remotes uses historical load to predict future annual increase in each community. The predicted increase is then used to calculate future peak load. Table 4-10 summarizes future annual increase, peak load for 2017-2022 and current station rating and connection limit by community. The community load is highlighted in yellow where it is forecast to exceed the connection limit and highlighted in orange where it is forecast to exceed the station capacity.

To account for the load growth, Remotes has scheduled six generating station upgrades in the next five years in Big Trout Lake, Wapekeka, Sandy Lake, Weagamow, Fort Severn, and either Deer Lake or Kasabonika, depending on the actual load growth and the availability of INAC funding.

Table 4-10: Forecast Peak Load by Community

| Community | Future Annual Increase | Peak Load (kW) 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | Station Rating (kW) | Connection Limit (kW) |
|---|---|---|---|---|---|---|---|---|---|
| **Armstrong** | 3.0% | 1035 | 1066 | 1098 | 1131 | 1164 | 1199 | 1450 | 1233 |
| **Bearskin Lake** | 2.5% | 614 | 629 | 645 | 661 | 678 | 695 | 1000 | 850 |
| **Big Trout Lake** | 4.0% | 1381 | 1436 | 1493 | 1553 | 1615 | 1680 | 1600 | 1360 |
| **Biscotasing** | 0.0% | 100 | 100 | 100 | 100 | 100 | 100 | 156 | N/A* |
| **Deer Lake** | 4.0% | 1340 | 1394 | 1449 | 1507 | 1568 | 1630 | 1795 | 1526 |
| **Fort Severn** | 6.0% | 689 | 730 | 774 | 821 | 870 | 922 | 1000 | 850 |
| **Gull Bay** | 1.0% | 314 | 317 | 320 | 324 | 327 | 330 | 430 | 366 |
| **Hillsport** | 0.0% | 80 | 80 | 80 | 80 | 80 | 80 | 125 | N/A* |
| **Kasabonika** | 4.5% | 1156 | 1208 | 1262 | 1319 | 1378 | 1440 | 1600 | 1360 |
| **Kingfisher Lake** | 4.0% | 652 | 678 | 705 | 734 | 763 | 793 | 1055 | 897 |
| **Lansdowne** | 5.0% | 584 | 613 | 644 | 676 | 710 | 745 | 875 | 744 |
| **Marten Falls** | 1.5% | 501 | 509 | 517 | 524 | 532 | 540 | 650 | 553 |
| **Oba** | 0.0% | 75 | 75 | 75 | 75 | 75 | 75 | 120 | N/A* |
| **Sachigo Lake** | 3.0% | 731 | 753 | 775 | 799 | 823 | 847 | 1000 | 850 |
| **Sandy Lake** | 2.5% | 2535 | 2598 | 2663 | 2730 | 2798 | 2868 | 3050 | 2593 |
| **Sultan** | 0.0% | 130 | 130 | 130 | 130 | 130 | 130 | 150 | N/A* |
| **Wapekeka** | 3.0% | 651 | 670 | 691 | 711 | 733 | 755 | 865 | 735 |
| **Weagamow** | 3.0% | 1062 | 1094 | 1127 | 1160 | 1195 | 1231 | 1425 | 1211 |
| **Webequie** | 2.0% | 660 | 673 | 687 | 700 | 714 | 729 | 1000 | 850 |

**no load growth*

### 4.1.7.2 Smart Grid Development

Remotes' investment plan includes the installation of Viper switches on the distribution system to improve reliability and cold-load pickup. SCADA and PLC upgrades at Remotes' generating stations will also facilitate a more dynamic and responsive grid operation, providing improved acquisition and alarm handling capabilities from a remote location. In some situations, this will allow for remote monitoring, control and restoration of power after an interruption.

#### 4.1.7.3 REG Accommodation

A biomass project is being developed in Whitesand under Remotes' REINDEER program in cooperation with the IESO. If the project develops as planned, it is anticipated that electrical output could displace electrical load within the community and that settlement would be based on the avoided cost of diesel fuel in that community. No project timeline has yet been developed for the construction of this project.

Another project, supported by federal and provincial grants, is currently being developed by Fort Severn First Nation and private sector developers. Remotes' role in this project is to ensure the ongoing reliability and stability of the existing microgrid and to ensure that the project can be integrated into the existing generation system. The project is staged, with 40 kW of net-metered solar installed to date. When fully installed, the project will qualify for Remotes' REINDEER program and, consistent with that program, Remotes will pay for the electricity produced based on the avoided cost of diesel fuel.

A 360-kW solar/battery microgrid project, supported by provincial grants, is also planned for Gull Bay. The project is currently in the very early stages. It is anticipated that the project will also qualify for Remotes' REINDEER program and that settlement will also be based on the avoided cost of diesel fuel in that community.

### 4.1.8 Customer Preference, Technological Opportunity, Innovation (5.4.1h)

A list and brief description of projects/programs planned in response to customer preferences (e.g. data access and visibility, participation in distributed generation, load management); to take advantage of technology-based opportunities to improve operational efficiency, asset management, and the integration of distributed generation and complex loads; and to study or demonstrate innovative processes, services, business models, or technologies is provided below.

#### 4.1.8.1 Customer Preferences

Distribution system investments in the system access category are initiated by customers. The total capital costs of these programs are shown in Table 4-11.

Table 4-11: Customer-requested Distribution Projects

| Project | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| Service Cancellations | 148,000 | 173,000 | 182,000 | 186,000 | 190,000 |
| Fixed Price Layouts | 106,000 | 124,000 | 130,000 | 133,000 | 136,000 |
| New Customer Connections & Service Upgrades | 658,000 | 768,000 | 809,000 | 824,000 | 840,000 |
| **Total (gross)** | **912,000** | **1,065,000** | **1,121,000** | **1,143,000** | **1,166,000** |
| Contributions & Removals | (912,000) | (1,065,000) | (1,121,000) | (1,143,000) | (1,166,00) |
| **Total (net)** | **0** | **0** | **0** | **0** | **0** |

Generator upgrades are also customer-requested. Table 4-12 lists the total capital cost of the generator upgrades planned over the forecast period.

Table 4-12: Customer-requested Generation Projects

| Project | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| BTL-Wapekeka Upgrade & Connection | 2,149,000 | 3,252,000 | 1,364,000 | 0 | 0 |
| Deer Lake or Kasabonika | 0 | 0 | 0 | 1,364,000 | 4,962,000 |
| Fort Severn | 0 | 0 | 3,042,000 | 3,657,000 | 0 |
| Sandy Lake | 367,000 | 881,000 | 1,311,000 | 0 | 0 |
| Weagamow | 2,832,000 | 1,993,000 | | 0 | 0 |
| **Total (gross)** | **5,348,000** | **6,126,000** | **5,717,000** | **5,021,000** | **4,962,000** |
| Contributions & Removals | (5,348,000) | (6,126,000) | (5,717,000) | (5,021,000) | (4,962,000) |
| **Total (net)** | **0** | **0** | **0** | **0** | **0** |

## 4.1.8.2 Technology-based Opportunities

Planned investments into PLC and SCADA systems, as well as fuel tank controllers will improve operational efficiency and asset management capabilities. These investments entail communication upgrade, SCADA hardware and software upgrade, and PLC hardware and software upgrade. Table 4-13 lists the planned expenditures over the forecast period.

Table 4-13: Projects in response to Technology-based Opportunities

| Project | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| SCADA & PLC Replacements & High-Speed Internet | 505,000 | 726,000 | 675,000 | 391,000 | 353,000 |
| Sandy Lake & Biscotasing - Bulk Tank Platform & Controls | - | - | - | - | 495,000 |
| **Total** | **505,000** | **726,000** | **675,000** | **391,000** | **848,000** |

## 4.1.8.3 Innovative Processes, Services, Business Models, or Technologies

Remotes has not planned any projects/programs to study or demonstrate innovative process, services, business models, or technologies.

## 4.2 Capital Expenditure Planning Process Overview (5.4.2)

### 4.2.1 Planning Objectives, Assumptions, and Criteria (5.4.2a)

Business planning is performed annually and focuses on the development of a six-year plan. The current plan contains the detailed 2017 budget and the 2018 to 2022 forecast. The business plan incorporates the same strategic objectives outlined in Section 3.1.1.

To facilitate the preparation of the business plan, an economic outlook is developed and included with the planning instructions issued. This includes forecasts of key economic statistics, interest rates, labour escalation rates, income tax rates, and cost rates for benefits.

Remotes manages its diesel generating stations by limiting the peak load at the station to 85% of the station's rating (known as the connection limit). This threshold allows for consumption growth as existing customers connect more devices to the grid without compromising the ability to supply power during peak load. When the peak load in the community nears the connection limit and additional load growth is forecast, the station upgrade planning process commences. In communities where there is no load growth, the connection limit is not relevant planning criteria. These communities have a high number of seasonal customers and the peak loads often occur on holiday weekends.

Remotes currently owns REG facilities in Big Trout Lake (wind), Deer Lake (hydroelectric), Kasabonika (wind), and Sultan (hydroelectric). New facilities are planned in Fort Severn (net-metered solar) and Gull Bay (solar/battery). A biomass generating station is planned in Whitesand. Customers in Big Trout Lake and Wapekeka have requested an additional 67.5 kW of community-owned solar generation, to be placed on appropriate non-Standard A customer accounts. Remotes' customers also have the ability to install their own REG facilities and sell power to Remotes; 15 small customer-owned solar net metering projects are now in service.

### 4.2.2 Non-Distribution System Alternatives to Relieving Capacity (5.4.2b)

Remotes' service areas do not include large industrial customers who offer the most potential for effective demand response and other peak shaving programs. Remotes engages in CDM activities as described in Section 1.4.4; however, Remotes' customers have expressed a disinterest in CDM and a preference towards REG. Further customer engagement has emphasized electricity availability rather than CDM (see Appendix E: 2016 Customer Workshop). Therefore, when relieving system capacity and operational constraints, Remotes considers alternatives on both the distribution and generation side, including REG investments, as well as the planned transmission system connection.

### 4.2.3 Processes, Tools, and Methods (5.4.2c)

The typical annual business planning process consists of six stages:

1. Strategic direction and goals established;
2. Risk review and investment requirements;
3. Confirmation of strategic direction and goals with Hydro One Inc.;

4. Development of economic outlook and forecast assumptions;
5. Development of plans and work programs; and
6. Approval by Hydro One Inc. Senior Management and Board of Directors.

Capital expenditures are identified based on Remotes' asset management process (as described in Section 4.2.3). Annually, required investments are determined based on asset condition, engine hours, load growth and external factors such as INAC funding and winter roads.

Several projects/programs are treated as non-discretionary since they are customer-initiated and fully recoverable. These include:

- Generator upgrades;
- New customer connections and service upgrades;
- Fixed price layouts; and
- Service cancellations.

Other investments are then ranked against seven risk categories: customer/reliability, regulatory, financial, operational efficiency, environmental, safety, and reputation. The outcome of this process is a list of investments that is consistent with Remotes' strategic goals and considers levels of investment and associated risk mitigation. A final investment plan is then endorsed and confirmed by the Hydro One Inc. senior management team.

The decision to defer a project due to limited resources is made based on risk. Typically, civil projects, motor controller upgrades, and PLC upgrades are deferred when required.

## 4.2.4 Customer Engagement (5.4.2d)

### 4.2.4.1 Customer Acceptance and Feedback

Generation upgrade projects are championed by the community in need of capacity. When Remotes has determined that a generation upgrade is needed, it approaches the community to inform them and the community must apply to INAC for funding. If the community decides not to support the upgrade, then they would not apply for funding and the project would not go through. Therefore, generation upgrade projects identified in this DSP are supported by the communities in which the upgrades will occur.

Remotes revised its capital processes in response to feedback from its customers and a decreasing availability of funding from the federal government. In the past, there were ongoing connection constraints due to an unavailability of funding from INAC. Remotes' new generation upgrade process reduces both the cost and time required for generation upgrades and has reduced the number of communities with connection restrictions.

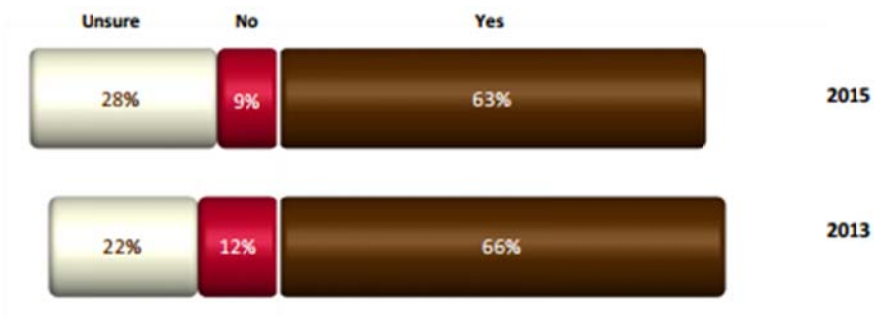
### 4.2.4.2 Customer Surveys

In 2015, Viewpoints Research conducted its most recent telephone survey of 205 residential, business, and government-supported organization customers served by Remotes. Many of the questions in this survey have been tracked from earlier customer surveys administered about every two years since 2003. In addition to the customer satisfaction results discussed in Section 2.3.1.1, other findings of the customer survey which reflect customer needs, priorities, and preferences include improved reliability, handling of customer contact, ways to improve service, helpfulness of staff, and environmental protection. The complete customer survey is attached as Appendix D: Customer Satisfaction Survey Results.

**Environmental Protection**

Sixty-three per cent of respondents said Remotes takes environmental protection in the community seriously down three per cent since 2013. Nine per cent said Remotes does not take it seriously, also down three per cent since the previous survey. Twenty-eight per cent of respondents were unsure.

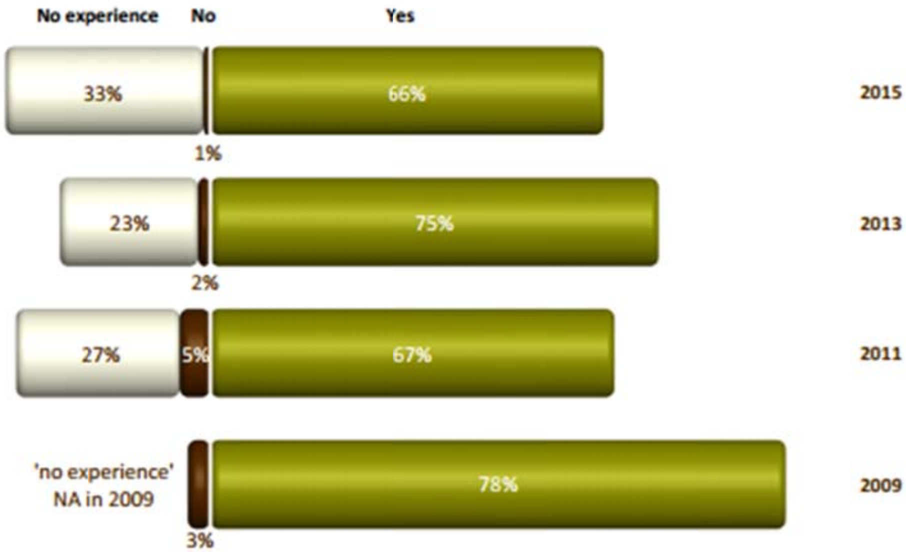
Figure 4-3: Does Remotes Take Local Environmental Protection Seriously?




**Staff is Polite & Helpful**

Sixty-six per cent of customers indicated that Remotes' personnel are generally polite and helpful when they come to their community to do things such as bring the electricity back on, which is nine per cent less than the previous survey and its lowest since tracking began on this question in 2009. On the contrary, just one per cent of customers said staff are not polite and helpful, which is the most favourable response achieved to date. One in three customers said they did not have any experience to answer this question.

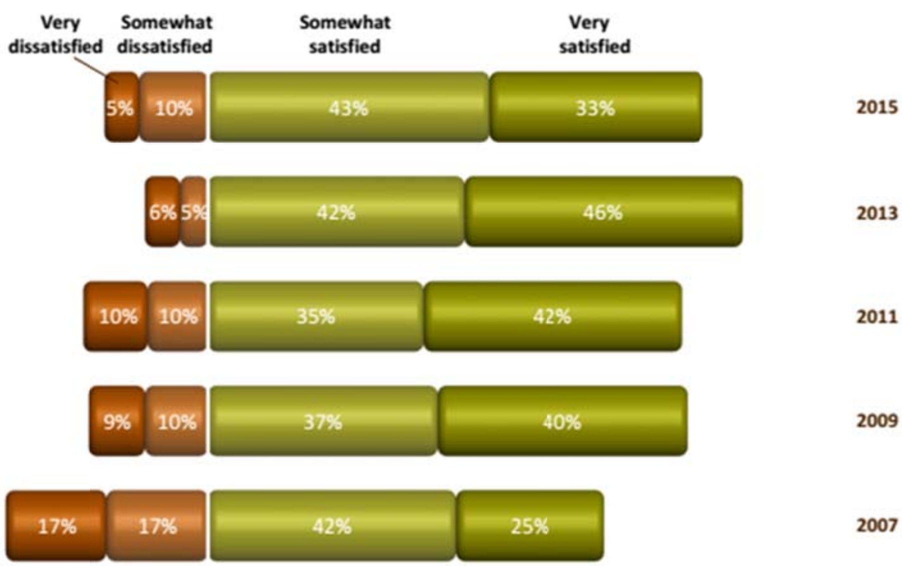
Figure 4-4: Staff Polite & Helpful




**Handling of Customer Contact**

When customers call Remotes' office, they can expect a person to answer the phone within 30 seconds. Figure 4-5 illustrates customer satisfaction with problem resolution. Between 2013 and 2015, customer satisfaction with how Remotes handled their contact dropped from 88% to 76%, but is still the second highest satisfaction rating since tracking began. Those who said they were very satisfied with their contact with Remotes is down 13% to 33%, its lowest level since 2007.

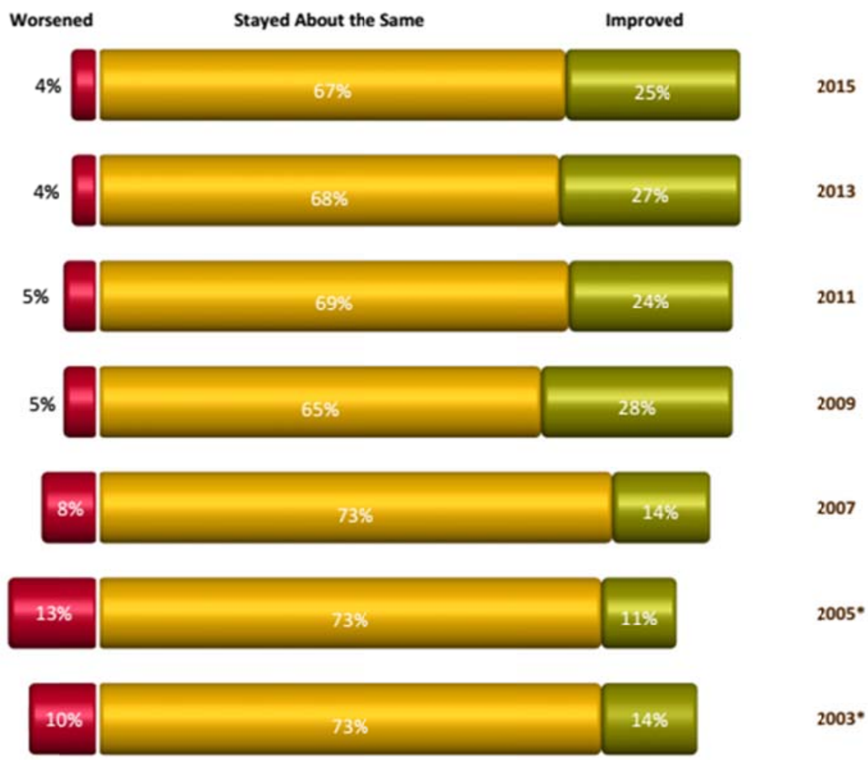
Figure 4-5: Customer Satisfaction with Problem Resolution



**Perceptions of Reliability**

Figure 4-6 illustrates changes in customers' impressions of their electrical service since 2003. After remaining stable below 15% from 2003 to 2007, the proportion of customers who believe the reliability of their electricity service has improved in the past few years has remained at or above 24% since. In 2015, 25% said they believe reliability has improved, while 67% of customers said it has stayed about the same. The proportion of customers who believe the reliability has worsened is approximately four per cent.

Figure 4-6: Customer Impression of Reliability

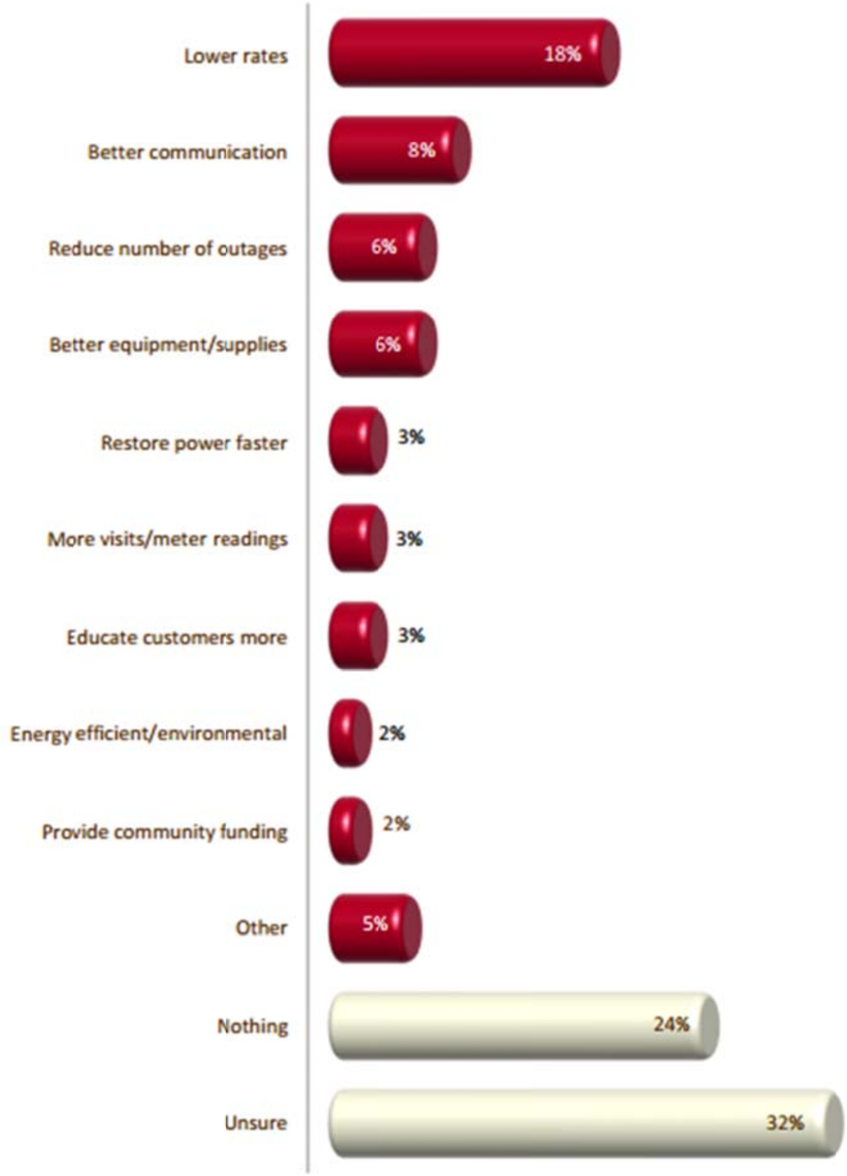



*In these years, respondents were given the option to say that reliability has worsened/improved somewhat or a lot. These responses have been combined on this chart.*

**Ways to Improve Service to Customers**

When asked what Remotes could be doing to improve service to customers, the most frequently mentioned improvement is lowering rates (mentioned by 18% of customers). The desire for better communications was mentioned by eight per cent of respondents, while reducing the number of outages and using better equipment and supplies were each mentioned by six per cent of respondents. When respondents offered an answer that could not be classified on the list of response categories provided to interviewers, their answers were recorded verbatim by the interviewer. Figure 4-7 summarizes the response to this question.

Figure 4-7: Ways to Improve Service Identified by Customers




## 4.2.5 REG Investment Prioritization (5.4.2e)

Remotes' customers have indicated that REG is important to them; therefore, the accommodation of REG is given high priority in terms of resources made available by Remotes. However, plans to install new REG in three communities are funded by the communities themselves through INAC and are compared to other investments by Remotes as part of the rate base. Remotes will pay the communities for the power produced based on the diesel fuel cost avoided.

## 4.3 System Capability Assessment for REG (5.4.3)

### 4.3.1 Forecast REG Connections (5.4.3a/5.4.3b)

Remotes' service areas are not included in the FIT program offered by the IESO. However, Remotes provides its customers with the option to install REG and sell energy to the grid based on the avoided diesel fuel cost.

A biomass project is being developed in Whitesand under Remotes' REINDEER program. If the project develops as planned, it is anticipated that electrical output could displace electrical load within the community and that settlement would be based on the avoided cost of diesel fuel in that community. No project timeline has yet been developed for the construction of this project.

Another project, supported by federal and provincial grants, is currently being developed by Fort Severn First Nation and private sector developers. Remotes' role in this project is to ensure the ongoing reliability and stability of the existing microgrid and to ensure that the project can be integrated into the existing generation system. The project is staged, with 40 kW of net-metered solar installed to date. When fully installed, the project will qualify for Remotes' REINDEER program and, consistent with that program, Remotes will pay for the electricity produced based on the avoided cost of diesel fuel.

A solar/battery microgrid project, supported by provincial grants, is also planned for Gull Bay. The project is currently in the very early stages. It is anticipated that the project will also qualify for Remotes' REINDEER program and that settlement will also be based on the avoided cost of diesel fuel in that community.

Fifteen small customer-owned solar net metering projects are now in service.

### 4.3.2 REG Connection Capacity and Constraints (5.4.3c/5.4.3d)

There are no constraints on Remotes' distribution system that would prevent the connection of REG. The sizes of REG projects are limited by the load in the communities and the integration with existing generation.

### 4.3.3 Embedded Distributor Constraints (5.4.3e)

Remotes does not have an embedded distributor.

## 4.4 Capital Expenditure Summary (5.4.4)

Table 4-14 presents the historical and forecast capital expenditures and system O&M. Since this is Remotes' first DSP filing, historical years do not include plan and variance numbers for each investment category.

1 Table 4-14: Historical and Forecast Capital Expenditure and System O&M

| Category | Historical | | | | | | | | | | | | | | | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | | | 2014 | | | 2015 | | | 2016 | | | 2017 | | | 2018 | 2019 | 2020 | 2021 | 2022 |
| | Plan | Act | Var | Plan | Act | Var | Plan | Act | Var | Plan | Act | Var | Plan | Act* | Var | Plan | | | | |
| | $'000 | | % | $'000 | | % | $'000 | | % | $'000 | | % | $'000 | | % | $'000 | | | | |
| System Access | | 123 | | | 31 | | | 42 | | | 70 | | | 0 | | 0 | 0 | 0 | 0 | 0 |
| System Renewal – Distribution | | 756 | | | 504 | | | 544 | | | 760 | | | 501 | | 522 | 609 | 643 | 654 | 670 |
| System Renewal – Generation | | 3,401 | | | 3,615 | | | 1,288 | | | 2,434 | | | 1,728 | | 1,644 | 2,636 | 3,369 | 3,791 | 2,221 |
| System Service – Distribution | | 0 | | | 0 | | | 0 | | | 0 | | | 0 | | 0 | 0 | 0 | 0 | 0 |
| System Service – Generation | | 456 | | | (193) | | | (19) | | | 0 | | | 413 | | 505 | 726 | 675 | 391 | 848 |
| General Plant | | 691 | | | 677 | | | 473 | | | 914 | | | 1,085 | | 565 | 572 | 581 | 590 | 598 |
| **Net Capital Expenses** | **7,747** | **5,427** | **30%** | **6,834** | **4,634** | **-32%** | **6,058** | **2,328** | **-62%** | **5,060** | **4,178** | **-17%** | **3,727** | **3,727** | **-** | **3,236** | **4,543** | **5,268** | **5,426** | **4,337** |
| System O&M | 18,662 | 18,335 | 2% | 18,092 | 18,601 | 2% | 20,644 | 16,492 | -20% | 21,463 | 18,060 | -16% | 20,760 | 20,760 | - | 21,291 | 22,260 | 23,650 | 24,095 | 24,281 |
| **Total Spend** | **26,409** | **23,762** | **10%** | **24,926** | **23,235** | **-7%** | **26,702** | **18,820** | **-30%** | **26,523** | **22,238** | **-16%** | **24,487** | **24,487** | **-** | **24,527** | **26,803** | **28,918** | **29,521** | **28,618** |

2 **0 months of actual data included in 2017.*

### 4.4.1 Variances in Net Capital Expenditures

The variances in the system access category cannot be calculated as a percentage since there is no planned spending each year based on 100% contributed capital. Therefore, variances in this category are due to not all the cost being recovered from customers.

The annual Remotes' capital and operation and maintenance work programs are subject to many different contributing factors beyond Remotes' control. This can result in large variances in the annual expenditures. Some of these factors include:

**Uncertainty of INAC funding**

Funding for growth-related capital is mainly a federal responsibility. INAC faces funding constraints and both the timing for funding approvals and amounts of funding available are uncertain and require planning flexibility. INAC funding approvals may be determined in-year, after Remotes' business plan is approved. INAC design, approval and funding cycles are also lengthy and complex in nature. In response to customer needs to connect to the electrical system, Remotes adjusts its planned work program to accommodate upgrade projects.

**Remote Community Accessibility**

Most of Remotes' communities are accessible only by air or winter roads. Due to the cost of air transportation, and to the size and weight of some of the equipment and materials required to perform work programs, winter roads are relied upon for transportation. If the appropriate weather conditions are not met in order to construct winter roads, it is not feasible to get the equipment and materials to site and therefore the work must be deferred.

**Failures**

Remotes maintains its fleet of generators as guided by the original manufacturer. Sometimes a unit may fail unexpectedly. Responses to failures are initially treated as maintenance. In order to maintain the supply of power to customers in remote communities and to be prepared for the next system contingency in the community, all failures are treated as an emergency. Because of the minimal generation redundancy, the failure of a subsequent unit may lead to a community going dark. Without running generators, the community has no power, lights, or water. This situation can lead to an evacuation of the community and damage to critical community infrastructure.

**Customer**

Whether generation or distribution in nature, Remotes strives to meet customer and community needs and commitments made to customers. Housing connections, often delay betterments as crews are moved to more impactive customer work. Generation upgrades are critical to community development and well-being, so other generation projects are deferred.

#### 4.4.1.1 2013 Net Capital Variances

2013 net capital expenditures were 30% below plan due to the following:

- Delayed Start for two generator unit replacements in Lansdowne due to the failure of the Deer Lake B unit;
- Re-prioritization of civil staff house improvement projects to instead focus on garage improvements in three communities;
- Deferral of protection upgrades and switchgear work due to increased engineering involvement in the planned replacements in Sandy Lake and Sachigo Lake;
- Redeployment of technical and management staff to the CIS project; and
- The nature of the work required to certify fire systems was determined to be maintenance in nature once the program started.

The variance was partially offset by:

- Unplanned costs for replacement of the Deer Lake B unit; and
- Increased engine overhauls (two additional units).

#### 4.4.1.2 2014 Net Capital Variances

Capital expenditures in 2014 were 32% below plan due to the following:

- A decision to cancel planned replacements of the Wapekeka C unit and the Fort Severn C unit due to an in-year agreement with INAC to fully fund an upgrade of both units;
- Bearskin B unit deferred due to lower than forecast operating hours;
- Marten Falls unit operating and reliability deficiencies were corrected, therefore the unit was not replaced;
- Lower than planned garage construction costs in two communities; and
- A decision to defer to 2015 some of the work associated with refurbishing the Sultan run-of-the-river hydroelectric plant after a catastrophic failure, as the work was more technically complex than originally expected.

The variance was partially offset by:

- Day-tank replacement work required to meet fuel code requirements; and
- Leaking roof of the Deer Lake staff house that necessitated capital repair and the completion of other civil work while staff were at site.

#### 4.4.1.3 2015 Net Capital Variances

Capital expenditures were 62% below plan due to the following:

- A decision to focus on fully recoverable INAC upgrade projects that would allow customers in three communities to connect to the electrical system. This resulted in the removal of connection restrictions for all three communities;
- Engine replacements were lower as they were completed within the scope of these upgrade projects; and
- Day tank improvements, the Wapekeka 600-V upgrade and capital betterments work were also deferred due to this shift in priorities.

The variance was partially offset by:

- Above-plan spending on the Lansdowne A unit engine replacement; and
- The completion of rebuild work at the Sultan run-of-the-river hydroelectric facility.

#### 4.4.1.4 2016 Net Capital Variances

Capital spending was 17% below budget due to the following:

- A decision to reprioritize work to focus on INAC-funded generation upgrades that would allow customers in two communities to connect to the electrical system;
- An engine replacement project was returned to inventory, showing a timing difference on annual capital spending;
- The deferral of the planned replacement of a generator in Hillsport and a generation sustainment project in Marten Falls to focus on INAC-funded upgrade work;
- Lower than planned cost to replace the Bearskin B unit; and
- The Shoulderblade hydroelectric generator rebuild cost less than estimated as the required work was not as significant as expected.

The variance was partially offset by:

- The unplanned replacement of Deer Lake unit B.

### 4.4.2 Trends in Capital Expenditures

The average annual spending in the system access category over the historical period[1] was $53k. System access programs are fully recoverable and are budgeted so. However, occasionally a new-connect is only 50% recoverable from the customer. As this is very rare, it is not budgeted for. The resulting average actual costs come from these partially unrecoverable new connects and also from the net costs of fixed price billings, where the work could not be fully bundled with other work in the community. The forecast spending is $0 each year since programs in this investment category are fully-recoverable.

The average annual spending on distribution system renewal over the historical period[1] was $613k, while the average annual forecast spending is $619k. Although the number of distribution assets under management by Remotes is expected to increase over the forecast period when the new communities are added to the service area, no major increase in distribution system renewal spending has been planned since INAC is funding upgrades to the distribution lines before they are transferred to Remotes. Increased metering costs have been budgeted based on the anticipated service area additions.

The average annual spending on generation system renewal over the historical period[1] was $2.493M, while the average annual forecast spending is $2.732M. Over the historical period, some investments in this category were either deferred or transitioned to a fully-recoverable generator upgrade project. Planned investments over the forecast period to replace generators, overhaul generators, and civil repair work at diesel generating stations are based on the conditions of the respective assets.

[1] 2017 spending based on budgeted amount only.

There were no expenditures in the distribution system service category over the historical period and none have been budgeted over the forecast period.

The average annual spending on generation system service over the historical period[1] was $131k, while the average annual forecast spending is $629k. Gross spending in this category is dominated by generator upgrades, but these costs are fully recoverable. The non-recoverable portion of these costs is mostly attributed to SCADA, PLC, and fuel tank control upgrades. In 2013, Remotes attempted to contract resources to complete the SCADA and PLC project, as specialized information technology, networking, and programming skills are required to complete this project. SCADA and PLC investments were made, but were subsequently expensed in 2014 when the capital portion of the project did not materialize. During 2014 and 2015, Remotes attempted to hire contract staff to perform the work but were unsuccessful due to the unusual nature of Remotes' business and the specific needs required for the system. It was then determined that this type of work required a full-time dedicated professional, with specialized expertise, and the position was filled in 2015. Additional SCADA and PLC upgrades have been budgeted for 2017 and each year of the forecast period. Fuel system improvements were made in Lansdowne in 2013 for $140k and a larger scope of work is planned in 2022 to upgrade the bulk tank platforms and controls in Sandy Lake and Biscotasing (estimated to be $495k).

The average annual spending on general plant over the historical period[1] was $768k, while the average annual forecast spending is just $581k. Facilities improvements in Lansdowne, Kasabonika, and Deer Lake over the historical period were more extensive than those budgeted over the forecast period. Investments into garages, water wells, and the Beaverhall maintenance shop over the historical period were likewise more extensive than the planned improvements over the forecast period.

## 4.5 Justifying Capital Expenditures (5.4.5)

### 4.5.1 Overall Plan (5.4.5.1)

#### 4.5.1.1 Comparative Expenditures by Category over the Historical Period

Comparative capital expenditures by investment category over the historical period are presented in Table 4-15.

Table 4-15: Historical Net Capital Expenditures by Category

| Investment Category | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | 2017 Budget |
|---|---|---|---|---|---|
| System Access | 122,909 | 30,765 | 42,407 | 69,913 | 0 |
| System Renewal – Distribution | 755,858 | 504,031 | 543,694 | 759,715 | 501,360 |
| System Renewal – Generation | 3,401,157 | 3,615,497 | 1,287,531 | 2,434,356 | 1,728,000 |
| System Service – Distribution | 0 | 0 | 0 | 0 | 0 |
| System Service – Generation | 456,184 | (193,493) | (18,768) | 0 | 413,000 |
| General Plant | 690,724 | 677,492 | 472,718 | 914,193 | 1,085,000 |
| **Total** | **5,426,832** | **4,634,292** | **2,327,582** | **4,178,177** | **3,727,360** |

#### 4.5.1.2 Forecast Impact of System Investment on System O&M Costs

Table 4-16 lists summarizes the forecast system O&M spending into four categories: distribution, generation, common (i.e. northern strategies and community relations), and environment (e.g. waste management, spill management and monitoring, incident follow-up, environmental management system implementation).

Table 4-16: Forecast System O&M Expenditures

| Investment Category | 2018 Budget | 2019 Budget | 2020 Budget | 2021 Budget | 2022 Budget |
|---|---|---|---|---|---|
| Distribution O&M | 4,393,000 | 5,055,000 | 5,567,000 | 5,671,000 | 5,496,000 |
| Generation O&M | 15,496,000 | 15,786,000 | 16,737,000 | 17,024,000 | 17,315,000 |
| Common O&M | 339,000 | 336,000 | 241,000 | 273,000 | 320,000 |
| Environment O&M | 1,063,000 | 1,083,000 | 1,105,000 | 1,127,000 | 1,150,000 |
| **Total** | **21,291,000** | **22,260,000** | **23,650,000** | **24,095,000** | **24,281,000** |

Remotes investigated the relationship between capital spending and system O&M costs. Regardless of the capital spending, generator maintenance is required every 2,500 engine-hours. Due to the associated flight and fuel costs of this maintenance, there is no reduction to system O&M costs from capital investment.

#### 4.5.1.3 Investment Drivers by Category

The investment drivers by category are presented in Table 4-17.

Table 4-17: Investment Drivers by Category

| Investment Category | Drivers | Projects/Activities |
|---|---|---|
| System access | Customer service requests | New customer connections and service upgrades<br>Fixed price layouts<br>Service cancellations |
| System renewal | Assets failure | Damage claims<br>Defective meter replacements |
| | Assets at the end of their service life due to failure risk | Small external demand requests<br>Distribution system improvements<br>Generator replacements<br>Generator overhauls<br>Diesel plant civil improvements<br>Day and bulk fuel tank replacements |
| System service | System capacity | Generator upgrades |
| | System reliability and operational efficiency | SCADA and PLC upgrades |
| General plant | Non-system physical plant | Housing improvements<br>Storage buildings and miscellaneous civil projects<br>Minor fixed assets |

#### 4.5.1.4 REG Requirements

As per the REG capacity assessment in Section 4.3, there are no constraints on Remotes' system that would prevent the connection of REG. The sizes of REG projects are limited by the load in the communities.

### 4.5.2 Material Investments (5.4.5.2)

The focus on this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements. For this Application, the threshold is $283,000. Appendix A presents the project narratives for the material investments in the 2018 Test Year.

# Appendix A: Business Cases for Material Investments

# Material Investments in the 2018 Test Year

## Table of Contents

# New Customer Connections & Service Upgrades

## 1. Project/Program Description

### 1.1.Current Issue

Capital projects included under this program are customer-initiated requests for connection to Remotes' distribution system and/or expansion of connection capacity to accommodate such requests. With population changes and more intensive use of electricity in remote communities, the overall number of new load connections for Remotes has increased in recent years and is expected to continue growing.

### 1.2. Project Scope

New customer connections vary from year to year and may include provision/expansion of distribution lines, transformers, switches, fuses, meters, and electrical termination facilities.

### 1.3. Main and Secondary Drivers

This program is driven by customer service requests, as per Table 1-1 in Remotes' DSP.

### 1.4. Performance Targets and Objectives

Responding to customer requests is a key factor in maintaining customer satisfaction. Remotes tracks customer satisfaction levels by way of a third-party survey issued every second year, reporting the results as a part of its scorecard.

## 2. Project/Program Justification

### 2.1. Information Used to Justify the Investment

Investments in this program are initiated by customers and 100% recoverable, as specified in Remotes' asset management process.

### 2.2. Alternatives Evaluation

**Alternative 1: Do nothing**

Access to electricity is a key quality of life indicator, so the "do nothing" option is therefore not feasible.

a) Project Design/Implementation Options

New connections and service upgrades are planned using standardized designs that meet the requirements of *O. Reg. 22/04*, made under the *Electricity Act, 1998*.

## 2.3. Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

| | Historical Costs ($ '000) | | | | | Future Costs ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017*** | **2018** | **2019** | **2020** | **2021** | **2022** |
| Capital (Gross) | 477 | 437 | 559 | 342 | 629 | 658 | 768 | 809 | 824 | 840 |
| Contributions | (354) | (432) | (537) | (317) | (629) | (658) | (768) | (809) | (824) | (840) |
| Removals | (13) | (1) | (18) | (3) | - | - | - | - | - | - |
| **Net Capital** | **110** | **5** | **5** | **22** | **-** | **-** | **-** | **-** | **-** | **-** |
| O&M | - | - | - | - | - | - | - | - | - | - |

*0 months of actual spending included in 2017

b) Start Date
January 1, 2018

c) In-Service Date
December 31, 2018

d) 2018 Test Year Expenditure Timing

| | Forecast Cost ($ '000) | | | |
|---|---|---|---|---|
| | **Q1** | **Q2** | **Q3** | **Q4** |
| Capital (Gross) | 164.5 | 164.5 | 164.5 | 164.5 |
| O&M | - | - | - | - |

e) Comparative Expenditure Information

The work varies year-to-year based on the size, nature, and volume of construction activities in the communities.

## 2.4. Project Benefits

a) Operation Efficiency and Cost Effectiveness

New connections and service upgrades are planned using standardized designs that meet the requirements of *O. Reg. 22/04*. In doing so, Remotes manages the engineering and design costs of these projects, while providing consistent design quality throughout its service territory. Since these programs are customer-funded, the resulting cost savings are passed directly on to customers.

b) Customer

The net benefit to customers is connection to the electrical system.

c) Safety

All new construction conforms to the latest standards for health and safety protections and performance.

d) Cyber-Security, Privacy

New smart meters installed under this program as part of the customer connection or service upgrade meet the latest cyber-security standards.

e) Co-ordination and Interoperability

As for all customer-initiated projects, Remotes works closely with the First Nation community when planning and funding the projects.

f) Economic Development

Connecting new customers to the system encourages economic growth in the community.

g) Environment

The investment will not have any negative environmental effects. Where the scope of a project includes the replacement of distribution transformer(s), newly-procured transformer units meet the latest standards in energy efficiency.

h) Final Economic Evaluation

N/A

i) System Impacts

The connection of new customers to the system impacts the system capacity relative to Remotes' planning criteria and, therefore, impacts the ability to connect additional customers in the future. Remotes accounts for this impact during its planning and works closely with the communities it serves to ensure adequate system capacity is in place to serve their immediate and future needs.

# 3. Prioritization

This is a non-discretionary program since it is driven by customer service requests and the costs are fully recoverable.

# 4. Execution Path

## 4.1. Implementation Plan

Projects within the program are requested by customers. Customers follow a standardized connection process by calling Remotes customer service department. At a high level, the process includes requesting service, designing the layout, and setting up an account. Once the Electrical Safety Authority (ESA) has inspected the premises, connection and construction work takes place after payment is received.

## 4.2. Risks and Risk Mitigation

Connections are priced two ways: variable or fixed. The costs of variable connections 100% recovered and billed as incurred. To maintain affordability of fixed-price connections, travel costs are assumed to be zero and must be coordinated with other work in the community. Every effort is made to fully recover the costs of fixed-price connections; however, when coordination with other work is not possible, fixed-price connections can be under-priced based on the need to meet customer/OEB timelines.

### 4.3. Timing Factors

Year-over-year fluctuations in the volume of work performed under this program vary based on the number of customer requests received each year. The timing of work depends on when the customer request is made.

### 4.4. Cost Factors

The number of customer connections and service upgrades required each year are forecast based on historical trends. The volume of work fluctuates each year depending on the number of requests made by customers. In 2018, it is in anticipated that Cat Lake will be added to Remotes' service area, which has been accounted for in the plan.

Controllable costs are minimized by using standardized designs. Since projects under this program are completely recoverable, the cost savings are passed on to customers.

### 4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% of customers stated that having electricity when they need it is a key driver to their satisfaction. New customer connections and service upgrades allow customers to connect to Remotes' distribution system in their community and have vital access to electricity. Projects under this program are initiated by Remotes' customers.

### 4.6.Leave to Construct Approval

N/A

## 5. REG Investment Costs

N/A

# Distribution System Improvements

## 1. Project/Program Description

### 1.1. Current Issue

Decisions to proactively replace distribution system assets are based on inspection and asset condition assessment work performed in 2016. Poles which are hollow, exhibit severe surface rot, woodpecker damage, or otherwise identified to be unsafe, or in poor or very poor condition, require replacement. Leaning poles are realigned and substandard conductors are replaced where deficiencies are identified. Other distribution system defects related to transformers and other equipment are identified during field inspections can also necessitate capital replacement due to failure risk, safety concerns, or as otherwise applicable.

Most of Remotes' existing distribution assets were installed in the 1980s. To ensure a long-term sustainable approach to management of the distribution assets and to smooth out the potential revenue impacts of replacing all the assets in a very short window, Remotes performs betterments based on the age of the assets. Improvements to distribution systems in 2018 also include the installation of Viper switches which enable operators to sectionalize load to improve cold load pickup and to reduce the duration of community-wide distribution outages, by allowing immediate on-site outage response.

### 1.2. Project Scope

This program includes work on all distribution assets – primarily poles, but also conductors, distribution transformers, air break switches, reclosers, and step-up transformers. Major betterments are performed in one or two communities each year and minor betterments to address defects are performed in other communities.

The project scope in 2018 includes major betterments in Sultan and Bearskin Lake. The asset condition assessment identified 17 poles requiring replacement in Bearskin Lake and 32 poles requiring replacement in Sultan. Both major betterments include additional pole replacements to mitigate clearance hazards and substandard designs. In Sultan, the planned betterment work also includes replacing old poles in the community that were not necessarily identified as defective, but require replacement to mitigate uplift and design issues that are created by the replacement of surrounding poles. System bus upgrades may also be required because of the pole replacements. Due to work and planning efficiency and mobilization costs in remote communities, it is always preferred to bundle work.

Starting in 2013, Remotes began installing Viper switches in communities to improve cold load pick up and to enable the operator to respond to community-wide outages caused by problems on the distribution system that the operators are not qualified to respond to. Improvements planned for 2018 include Viper switches to be installed in Lansdowne and Fort Severn. These upgrades are expected to provide the local operator the flexibility to sectionalize load to improve reliability and improve the cold load pickup capability. Remotes plans to install at least one Viper switch in every mid- to large-sized community and is installing Viper switches in two communities per year as part of a multi-year plan.

## 1.3. Main and Secondary Drivers

The main driver for this investment in the system renewal category, as per Table 1-1 in Remotes' DSP, is assets at the end of their service life due to failure risk. The secondary drivers are improved reliability, safety, and cold load pickup on the distribution systems.

## 1.4. Performance Targets and Objectives

Improvements to the distribution systems are critical to maintain system reliability. Proactive replacement of assets under this program improves Remotes' customer-oriented performance and reduces the frequency of outage occurrences (the SAIFI metric). This investment targets outages due to defective equipment, foreign interference, and adverse weather. New Viper switches included in this program improve system reliability by reducing the duration of outages (the SAIDI metric). Reliability is one of the key drivers to customer satisfaction to Remotes' customers. This program also reduces distribution losses through replacement of substandard conductors and distribution transformers.

Improvements to distribution system assets are a key component of Remotes' asset lifecycle optimization policies and practices. Replacements and refurbishments of distribution assets include planned improvements and component replacement required to maintain the operation of distribution lines and associated equipment. Overhead line sections, wood poles, Viper switches, and distribution transformers are the highest priority assets under this program.

Improvements planned for 2018 include Viper switches to be installed in Lansdowne and Fort Severn. In Fort Severn, the fifteen-minute high cold load pickup was 746 kW in 2016, which exceeds the peak load in this community (i.e. 650 kW in 2015) by 15%. In Lansdowne, the cold load pickup was 647 kW in 2015, which exceeds the peak load in this community by 12%. New Viper switches in both locations will improve the cold load pickup and on-site trouble response options in these communities.

## 1.5. Condition of Assets

A detailed inspection on Remotes' poles was done in 2016 and their condition divided into three categories:

- Very Poor - emergency replacement,
- Poor - replace within five years,
- Good - no replacement within five years.

No poles were in very poor condition, but 115 poles were found to be due for replacement in the next five years. The replacements will be divided over the five-year period.

The poles assessed to be in poor condition in the communities of Bearskin Lake and Sultan are targeted in 2018.

| Condition | Very Poor | Poor | Good |
|---|---|---|---|
| **Community** | **Number of Poles** | | |
| Bearskin Lake | 0 | 17 | 284 |
| Sultan | 0 | 32 | 90 |

## 1.6. Customer Impact

a) Customer profile for each community:

| Customer Class | Non Std A – Res. | Non Std A – Seas. | Non Std A – GS 1P | Non Std A – GS 3P | Street Lightning | Std A – Res. – Air | Std A – GS – Air | Total |
|---|---|---|---|---|---|---|---|---|
| **Community** | **Number of Customers** | | | | | | | |
| **Bearskin Lake** | 123 | - | 11 | 4 | - | 9 | 27 | **174** |
| **Fort Severn** | 86 | - | 19 | - | 1 | 10 | 28 | **144** |
| **Lansdowne** | 72 | - | 5 | 2 | 1 | 8 | 16 | **104** |
| **Sultan** | 35 | 23 | 9 | - | - | - | - | **67** |

b) Customer impacts for each community:

The value of customer impact is defined as follows:

- High – less than ten per cent seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

| Community | Customer Count | Load at Risk (kW peak) | Value of Customer Impact |
|---|---|---|---|
| **Bearskin Lake** | 174 | 640 | High |
| **Fort Severn** | 144 | 650 | High |
| **Lansdowne** | 104 | 577 | High |
| **Sultan** | 67 | 186 | Medium (34% seasonal) |

A planned replacement of 17 poles in Bearskin Lake would likely require three two- to four-hour planned outages affecting 58 customers at a time. An unplanned outage in Bearskin involving a single pole failure would take eight hours to rectify (mobilize crew and flight, flight time, mobilization of pole and replacement on site). With 17 poles nearing end-of-life, such an outage may occur once or twice without the planned project. A similar one-pole failure in Sultan would require nine hours to rectify the outage, due to the longer flight time.

For Viper switches, the operator can respond to a community-wide distribution outage without having to dispatch a crew or can restore the service. The Viper switch is expected to reduce the duration of community-wide outages as well as lessen the adverse operating impacts on costly generation assets.

# 2. Project/Program Justification

## 2.1. Information Used to Justify the Investment

The investment is justified based on inspection results on the distribution system. The communities targeted for major betterments were last inspected in 2016 and the results indicate the need for proactive replacements.

## 2.2.Alternatives Evaluation

**Alternative 1: Do nothing**

In the case of the "do nothing" scenario, the assets are not replaced proactively and are instead run to failure.

**Alternative 2: Major betterment in another community**

One or two communities are selected for a major betterment each year; this alternative considers major betterments that could be done in other communities.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, the distribution assets are run to failure. System reliability and customer satisfaction would suffer due to an increased occurrence of outages. Given the remoteness of the company's service territory, proactive replacements are more cost effective than reactive replacements, as a variety of factors beyond the utility's control could interfere with its ability to conduct the work on a reactive basis. As such, run-to-failure is not an optimal approach in accordance with Remotes' asset lifecycle optimization policies and practices. Planned work results in shorter planned outages times compared to unplanned replacement and allows Remotes to notify its customers before work is done. Pole failures are highly impactful to customers and planned work. Trouble call responses in the remote communities are disproportionately costly to mobilize and very disruptive. In case of an unplanned outage, crews are often pulled from planned jobs and the customers are out of power until the crews can be mobilized and reach the locations.

The 2016 asset condition assessment determined that Sultan has the most poles in need of replacement. While this is a small community with less than 100 customers, 26% of the poles are in need of replacement. Eighty-nine per cent of the poles in this community were installed in 1980 or earlier. Most of the poles are cedar with limited initial treatment, which are attractive homes for birds and insects. Most of these poles were installed to a 40-foot standard and modernizing the distribution system to 45 feet will improve clearances and facilitate additional joint-use applications. Other factors affecting the prioritization of this community include:

- There is an opportunity to also relocate transformers to areas more accessible by vehicles, which will reduce future trouble call costs.
- The working efficiency is major factor for this project since Remotes does not have equipment on site. All vehicles (e.g. trucks, RBDs, backhoes) will need to be brought in, so it is much better to mobilize once.

Bearskin Lake has the second most poles in need of replacement, with 17 assessed to be in poor condition. As shown in Section 1.6(b), the value of customer impacts in this community is high since there are no seasonal customers. There are 174 customers served and 640 kW of peak load at risk.

Major betterments in this community include additional pole replacements to mitigate clearance hazards and substandard designs. Therefore, this community was selected for a major betterment.

b) Comparison of Project Timing Alternatives

Projects in this program are community-focused: increasing the rate of asset replacement in the community would overharvest the assets that can be expected to remain operable in the medium term, while decreasing the rate of asset replacement would not mitigate the failure risk to the system presented by the identified deficiencies of targeted assets. Remotes' asset lifecycle optimization policies and practices state that poles should be replaced before they fail, pose a safety hazard, or cause a service interruption. Where possible, these replacements are made when other planned work in the community is planned to increase efficiency (fewer trips to the community and lower mobilization costs in the community) and minimize the number of planned outages.

c) Analysis of Project Enhancements

The program includes "like-for-like" renewals of distribution assets, whereby an asset identified as a failure risk is replaced with a new asset that conforms to modern distribution system standards. As an enhancement to this program, new Viper switches are installed to improve the reliability and cold load pickup of the distribution systems. Without these new switches, it is expected that the duration of outages experienced by customers would increase. Some "like-for-like" asset renewals include improvement to the most up-to-date standards and practices.

Locations for Viper switches are determined based on the peak load, cold load pick-up needs, and analysis of existing assets in service. In Fort Severn, the fifteen-minute high cold load pickup was 746 kW in 2016, which exceeds the peak load in this community (i.e. 650 kW in 2015) by 15%. In Lansdowne, the cold load pickup was 647 kW in 2015, which exceeds the peak load in this community by 12%. New Viper switches in both locations will improve the cold load pickup and on-site trouble response options in these communities. Once the switches are installed, operators will be able to respond to abnormal situations without having to dispatch a crew. This saves the dispatch cost and delay for customers, typically four hours. Remotes plans to install two Viper switches each year until there is at least one switch in every mid- to large-sized community.

## 2.3. Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

| | Historical Costs ($ '000) | | | | | Future Costs ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017*** | **2018** | **2019** | **2020** | **2021** | **2022** |
| Capital (Gross) | 1,217 | 543 | 584 | 817 | 610 | 636 | 743 | 783 | 797 | 813 |
| Contributions | (271) | (138) | (72) | (59) | (134) | (140) | (164) | (172) | (176) | (176) |
| Removals | (250) | (64) | (54) | (67) | (73) | (76) | (89) | (94) | (96) | (98) |
| **Net Capital** | **697** | **340** | **458** | **692** | **403** | **420** | **490** | **517** | **525** | **539** |
| O&M | - | - | - | - | - | - | - | - | - | - |

*0 months of actual spending included in 2017

b) Start Date
Mid-summer

c) In-Service Date
Late fall

d) 2018 Test Year Expenditure Timing

| | Forecast Cost ($ '000) | | | |
|---|---|---|---|---|
| | **Q1** | **Q2** | **Q3** | **Q4** |
| Capital (Gross) | - | 210 | 210 | - |
| O&M | - | - | - | - |

e) Comparative Expenditure Information

Comparative costs over the historical period are shown in the table in Section 2.3a above. The historical and future costs include travel, labour, and materials.

## 2.4. Project Benefits

a) Operational Efficiency and Cost Effectiveness

The proactive replacement of distribution system assets allows Remotes to efficiently allocate its resources in a planned manner. In general, proactive replacements are more cost effective than reactive replacements.

b) Customer

Customers benefit from improved reliability, which is a key driver for customer satisfaction.

c) Safety

This investment reduces safety hazards posed by defective poles and other distribution equipment identified during inspections.

d) Cyber-Security, Privacy

The new Viper switches do not include two-way communication; therefore, there is no negative effect on cyber security.

e) Co-ordination, Interoperability

Remotes coordinates with the local First Nations and Band Councils when planning betterment projects.

f) Economic Development

Most of Remotes' customers are First Nations, and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. The investment will improve the reliability of electrical service, which is conducive to economic growth in the community.

g) Environment

The proactive replacement of distribution transformers included in this investment programs reduces the risk of an oil leak or spill from the deteriorated transformers earmarked for replacement. New distribution transformers installed in the field meet the latest energy efficiency standards.

h) <u>System Impacts</u>

Investments into new Viper switches will improve the cold load pickup of the distribution systems. The investment is also expected to reduce distribution losses via the conductor and distribution transformer replacements.

# 3. Prioritization

## 3.1. Criteria for Prioritization

This program is measured against the following four (4) risk categories:

1. Customer/reliability
2. Regulatory relationship
3. Financial
4. Reputation

a) <u>Customer/reliability</u>

Historical reliability is not tracked on an individual community level. An unexpected and sustained outage in Bearskin Lake would require approximately four hours to arrange a crew and respond on-site. Sultan would take approximately eight to ten hours to dispatch and resolve the issue. Without executing the proposed project, it is expected that the occurrence of outages would increase.

The expected magnitude of reliability improvements in Fort Severn and Lansdowne due to the installation of new Viper switches cannot be readily quantified; however, the installation of this equipment would allow immediate on-site operator response to restore power. The switches facilitate partial loading in case of a generator outage.

b) <u>Regulatory</u>

Without the project as planned, safety and reliability may be compromised, which would constrain Remotes' regulatory relationship.

c) <u>Financial</u>

Absent the project as planned, regular ongoing maintenance would be required on the lines and equipment, which would increase system O&M costs. Emergency repairs are not as efficient as planned maintenance. Trouble costs generally start at $10k due to transportation, while an emergency pole replacement could cost as much as $30k. Bundling the work into a planned project reduces mobilization costs in terms of transportation to the community and within the community itself. Once a crew is in the community, they must excavate a hole (if required to set the pole), load the pole on a pole-trailer, transport it to the location, erect the pole, attach wires and conductors, and frame it with the crossarm and insulators. It takes longer to load and transport a single pole several times than to load several poles at once.

The new Viper switch installations are designed to allow immediate on-site operator response, which reduces travel and trouble call costs.

d) Reputation

Customers deserve and desire power that is good, safe, and reliable.

### 3.2. Consequences of Deferral

Deferring the Distribution System Improvement program would increase the probability that the assets would fail during the year, negatively impacting system reliability. Reactive replacements are more expensive than proactive replacements. Deferred renewal of the distribution system would increase the investment needs in future years and would cause spikes in revenue requirement compare to balance year-over-year investments.

### 3.3.Priority

Customer-initiated work is Remotes' first priority. Capital and maintenance investments into assets (e.g. this program) are prioritized next.

## 4. Execution Path

### 4.1. Implementation Plan

The planned work will be completed by a dedicated lines crew experienced in this type of work. Major betterments in the communities are planned to reduce the amount of resources spent on travel. In the case of minor betterments, the crews typically spend a week in the community to perform the necessary capital and O&M work. Implementation depends on the final scope of work and resourcing. Planning and material lead times both affect the order of project implementation. Sultan is slightly preferred based on asset condition and lower past investment.

### 4.2.Risks and Risk Mitigation

Cost is the largest risk to Remotes' capital projects and programs, since it is costly to transport equipment and crews to the communities. Remotes mitigates this risk through prudent project planning and work execution according to standard operating procedures. Large tools and equipment are stored in each community to reduce costs and mitigate the availability risk.

While the timing and priority of assets to be replaced may change during the year, Distribution System Improvements are well understood and generally meet cost and timing objectives.

### 4.3.Timing Factors

Crews are stationed in Thunder Bay and Remotes keeps lodgings for its crews in each community it serves. There is just one lodging facility per community; therefore, only one crew may be working in a community at a time without resorting to renting additional lodging space. The risk to limited accommodation is mitigated through coordination between crews. If emergency work is required in a community, then the timing of the planned capital investment work may be adjusted.

The ability to safely fly in crews also affects the timing of the project. If for any reason the community is inaccessible, the timing of the project must be adjusted accordingly.

The intensity of asset investment is not expected to fluctuate significantly over the forecast period. In the case that additional emergency capital work on the distribution system is identified during the year, the project plan may be altered to reflect the new priority of the assets to be replaced.

### 4.4.Cost Factors

The final cost of the project is largely affected by transportation costs, but is also affected by labour and material costs. Remotes has significant experience in planning and managing the expenditures associated with its distribution plant, and spending on Distribution System Improvements generally aligns with the budget.

If this program were not executed, it is expected that O&M costs would increase due to more trouble calls to repair the distribution system assets that are not being renewed.

### 4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% stated that a reliable source of electricity is a key driver to their satisfaction. An important part of reducing number of outages is replacing distribution assets at their end-of-life, and keeping the distribution system in good condition.

Out of the surveyed customers who indicated that Remotes could improve their service, 32% cited "lower rates" as the most important factor to improve service. In response to these comments, this program has been paced over five years to reduce its rate impact, while still mitigating the risk of asset failures on the distribution system.

### 4.6.Leave to Construct Approval

N/A

## 5. REG Investment Costs

N/A

# Big Trout Lake A Generator Replacement

## 1. Project/Program Description

### 1.1.Current Issue

The A unit diesel generator in Big Trout Lake is forecast to reach 55,868 engine-hours in 2019 and is rated to be in very poor condition. The manufacturer's published recommendations for generators of this type include complete overhauls after 20,000 hours. In addition, Remotes has determined that a generator should be replaced after two rebuilds, generally at about 60,000 hours. Therefore, an engine replacement has been scheduled for this generator in 2019, with the procurement of the replacement generator to take part in 2018. Assets are often ordered and transported to site a year in advance, to mitigate transportation risks (e.g. bad weather conditions) and long lead times.

### 1.2. Project Scope

Unit A in Big Trout Lake is a medium-speed (1800 rpm), 600-kW unit. The generator was installed in 1996, making it the oldest medium-speed diesel generator deployed in Remotes' system. This unit was selected for replacement based on its age, the actual and forecast engine-hours, and its very poor condition.

### 1.3. Main and Secondary Drivers

The main driver for this investment, as per Table 1-1 in Remotes' DSP, is that the generator is at the end of its service life due to failure risk.

### 1.4.Performance Targets and Objectives

The proposed investment is consistent with Remotes' asset lifecycle optimization policies and practices for diesel generators. Replacement of a generator based on the maintenance history, engine-hours, reliability history, and age reduces outage risk, enhances system reliability, and improves generator efficiency.

System reliability is an important customer-oriented performance measure for Remotes. Remotes tracks its System Average Interruption Frequency Index ("**SAIFI**") and its System Average Interruption Duration Index ("**SAIDI**"), both of which are affected by the timely replacement of generators.

Improvements in fuel economy and emissions performance with new generation units would also result in improved generation efficiency and reduced greenhouse gas emission intensity, both of which are important performance measures for Remotes' customers.

One of Remotes' planning objectives is that the peak load in each community should not exceed 85% of the station rating. Before this limit is reached, an upgrade of the generating station is scheduled. The generation capacity in Big Trout Lake is 1600 kW and the corresponding connection limit is 1360 kW. In 2014 the peak load reached 1395 kW, exceeding the connection limit. A separate project planned for 2018 and 2019 to upgrade the generating station in Wapekeka and connect this community to Big Trout Lake by way of an overhead distribution line to relieve capacity constraints in both communities.

### 1.5. Condition of Assets

The A unit diesel engine-generator set in Big Trout Lake was installed in 1996. As of January 2, 2017, the unit has operated for a total of 48,064 engine-hours. The unit was previously overhauled twice: first in July 2005 after 20,148 engine-hours and then in June 2015 after 44,185 engine-hours.

At the time of proposed replacement in 2019, the generator is forecast to reach 55,868 hours. The unit is already in very poor condition as per asset condition assessment and should accordingly be replaced without undue delays.

### 1.6. Customer Impact

a) Customer profile for the community:

| Customer Class | Non Std A – Res. | Non Std A – Seas. | Non Std A – GS 1P | Non Std A – GS 3P | Street Lightning | Std A – Res. – Air | Std A – GS – Air | Total |
|---|---|---|---|---|---|---|---|---|
| **Community** | **Number of Customers** | | | | | | | |
| **Big Trout Lake** | 301 | - | 30 | 6 | - | 10 | 50 | **397** |

b) Customer impacts for each community:

The table below presents the customer impacts for each community. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

| Community | Customer Count | Load at Risk (kW peak) | Value of Customer Impact |
|---|---|---|---|
| **Big Trout Lake** | 397 | 1395 | High |

An unplanned outage in the community can be cleared in less than two hours if the operator can respond. Otherwise, the outage time varies depending on the problem. The minimum response time is four hours to dispatch a crew to Big Trout Lake. An unplanned replacement may take up to six months. Remotes maintains an up-to-date contingency analysis for its in-service generation units. If unit A fails, then the other units can continue to serve the load.

## 2. Project/Program Justification

### 2.1. Information Used to Justify the Investment

The A unit generator set in Big Trout Lake was installed in 1996 and has been operated for 48,064 engine-hours as of January 2, 2017. Its estimated engine-hours over the forecast period are shown in the table below.

| **Year** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|---|
| **Projected Engine-Hours** | 50,774 | 53,321 | 55,868 | 58,415 | 60,962 | 63,509 |

This generator has been overhauled twice and, as per Remotes' asset management process, it is more economical to replace the unit rather than overhaul it a third time. The asset condition assessment determined that this unit is in very poor condition requiring immediate replacement.

## 2.2. Alternatives Evaluation

**Alternative 1: Do nothing**

The "do nothing" option considers that the generator is run to failure without intervention.

**Alternative 2: Overhaul**

The second alternative to a generator replacement is to overhaul the unit.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, the generator is run to failure. An unplanned outage in the community can be cleared in less than two hours if the operator can resolve the issue. Otherwise, the outage time varies depending on the nature problem. The minimum response time is four hours to dispatch a crew to Big Trout Lake. If the failure is irreparable, the outage would likely last a day; otherwise there could be rolling blackouts in the community lasting about a week. This is not the preferred option.

After two overhauls, it is no longer economical to overhaul the generator for a third time. This generator has been overhauled twice previously; therefore, replacement is the preferred option.

b) Comparison of Project Timing Alternatives

If the project was deferred by one year, the probability of increased maintenance and the risk of a catastrophic failure would increase. There is a spare 400-kW unit in the community. In the case of a catastrophic failure, the outage would likely last a day, otherwise there could be rolling blackouts in the community. In the medium term, a replacement would need to be flown in on an emergency basis.

c) Analysis of Project Enhancements

This project is a like-for-like renewal and does not include any project enhancements.

## 2.3. Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

| | **Historical Costs ($ '000)** | | | | | **Future Costs ($ '000)** | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017*** | **2018** | **2019** | **2020** | **2021** | **2022** |
| Capital (Gross) | - | - | - | - | - | 767 | 1,423 | - | - | - |
| Removals | - | - | - | - | - | (77) | (142) | - | - | - |
| **Net Capital** | **-** | **-** | **-** | **-** | **-** | **690** | **1,281** | **-** | **-** | **-** |
| O&M | - | - | - | - | - | - | - | - | - | - |

*includes 0 months of actual expenditures

b) Start Date
January 2018

c) In-Service Date
September/October 2019

d) 2018 Test Year Expenditure Timing

| | Forecast Costs ($ '000) | | | |
|---|---|---|---|---|
| | **Q1** | **Q2** | **Q3** | **Q4** |
| Capital (Gross) | 383.5 | 383.5 | - | - |
| O&M | - | - | - | - |

e) Comparative Expenditure Information

The planned total gross cost of this investment is $2,190,000 spread over two years - 2018 and 2019, with procurement of replacement generators in 2018 and installation in 2019. To compare the cost to other engine replacement investments, cost per kW should be considered. The capacity of the generator is 600 kW, so the cost per kW is $3,650.

An engine replacement was done in Deer Lake in 2016. The unit replaced is a medium speed (1800 rpm) generator with capacity 635 kW. The total cost of this project was $902,931, which equates to $1,422 per kW. Another replacement was done on the A unit in Lansdowne in 2015, a medium-speed unit rated 275 kW. The total gross cost for this project was $871,190 and the cost per kW was $3,168.

The difference between the cost of these similar investments is primarily due to the difference between the stations. The station in Deer Lake is relatively new. The station in Big Trout was built in the 1980s and is much older and smaller than the Deer Lake station. New generators use digital controls, whereas the controls in the Big Trout Lake station are analogue. The replacement will improve the voltage regulation by moving to three phases rather than a single phase. Finally, Big Trout Lake is located further from all-weather roads and further from the manufacturer.

## 2.4. Benefits

a) Operational Efficiency and Cost Effectiveness

The investment supports operational efficiency since the new engine will be more fuel efficient. Auxiliary work is done alongside the replacement to reduce engine down-time, mobilization, and travel costs. The proactive replacement of a generator unit is cost effective compared to running the unit to failure, which would otherwise incur additional maintenance, outage, and emergency replacement costs.

b) Customer

The net benefit to customers is improved system reliability based on the proactive replacement of the generator.

c) Safety

The safety benefit of the proactive replacement of the generator is risk mitigation of an unplanned generator failure.

d) Cyber-Security, Privacy

The upgrade of auxiliary systems as part of the generator replacement will install fuel and control systems that comply with the latest cyber-security standards.

e) Co-ordination, Interoperability

Remotes uses standardized station designs and all new installations comply with *O. Reg. 22/04*.

Big Trout Lake has been identified to be connected to a new transmission line by an Order-in-Council issued by the Minister of Energy. The anticipated connection date is not presently known and the Regional Planning Process yielded a draft *Remote Community Connection Plan* requiring further consultation.

The planning co-ordinated with another project to connect the distribution systems of Big Trout Lake and Wapekeka and also co-ordinated with the local Band Councils.

f) Economic Development

Most of Remotes' customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. A reliable supply of electricity promotes economic growth in the region.

g) Environment

The new diesel generator set will meet the latest energy efficiency and emission performance standards, which have markedly improved since the existing unit was installed (1996). This will reduce the emissions. Furthermore, this investment ensures the reliable operation of this generator, which ensures the PLC can select the most fuel-efficient generator based on the load.

h) System Impacts

The reliable operation of Big Trout Lake Generator A will help maintain system performance.

# 3. Prioritization

## 3.1. Criteria for Prioritization

This program is measured against the following seven risk categories:

1. Customer/reliability
2. Regulatory
3. Financial
4. Efficiency
5. Environment
6. Safety
7. Reputation

a) Customer/reliability

Based on manufacturer guidelines, the probability of increased maintenance and the risk of a catastrophic failure would increase without the planned project. There is a spare 400-kW unit in the community. In the case of a catastrophic failure, the outage would likely last a day, otherwise there could be rolling blackouts in the community. In the medium term, a replacement would need to be flown in on an emergency basis.

b) Regulatory

Without the planned project, safety and reliability may be compromised, which would constrain Remotes' regulatory relationship.

c) Financial

Without the planned project, an increase in trouble with the unit is expected. The minimum response cost is $25,000. Emergency repairs are costlier since an engine may need to be procured and put in service quickly depending on the timing of its failure. Transportation costs for the unit would increase by about $100,000.

d) Efficiency

The new units are expected to be about four per cent more efficient than the older units, raising diesel fuel costs and emission levels.

e) Environment

New generators are designed to reduce emissions. The proactive replacement of the existing unit also mitigates the risk of a spill in the event of a failure.

f) Safety

Proper investment into diesel generators follow best practices recommended by manufacturers to ensure they operate safely.

g) Reputation

Customers deserve and desire power that is good, safe, and reliable.

### 3.2.Consequences of Deferral

Deferring this project would increase the probability that the generator fails, affecting reliability, regulatory relationship, financial risk, generator efficiency, environmental risk, safety risk, and reputation. This would affect the whole community of Big Trout Lake, approximately 400 customers.

### 3.3. Priority

The priority in 2018 is to purchase the engine and transport it to site to ensure that adequate generation is available to the community of Big Trout.

## 4. Execution Path

### 4.1. Implementation Plan

The 2018 costs include the design and procurement of the replacement unit. The replacement generator set is ordered in advance of winter roads. The installation, commissioning, and auxiliary upgrades will be performed in 2019. When integrating new engines into older existing systems; heating, cooling, ventilation, exhaust, electrical, fuel and control systems may be impacted. It is preferred that all necessary auxiliary work be done in conjunction with the engine replacement to reduce engine down-time, mobilization, and travel costs. The work will be done by a dedicated station crew and will be co-ordinated with another project to connect the distribution systems of Big Trout Lake and Wapekeka.

## 4.2. Risks and Risk Mitigation

The biggest risk to completion of the project as planned is in relation to costs and availability of transportation of the new generator to the community. This risk is mitigated through Remotes' staged implementation plan, in which the generator is procured one year earlier than the installation. However, despite the advance procurement, the unavailability of a winter road for an entire season may delay the project execution. If the risk of project delay becomes too great, then Remotes can hire a specialized aircraft to fly in the new unit, adding to the cost of the project.

Another risk to project completion is the availability of crew accommodation. Remotes has lodgings for only one crew in each community. Therefore, only one project can be implemented at a time in a community. If another project with a higher priority should suddenly come up in Big Trout Lake, it could affect the completion of this project. This can be mitigated by seeking to minimize the number of such emergencies through good planning and asset management. In the past, Remotes has also worked closely with the communities it serves to arrange for rental accommodation for its crews in case the lodgings are insufficient for the number of crews required.

Other risks to a project of this magnitude can occur due to manufacturing or installation defects. Remotes mitigates these risks by working closely with its suppliers, assigning trained personnel who are familiar with generator station commissioning, and performing commissioning testing.

## 4.3.Timing Factors

The project timing has been planned as per the implementation plan to allow the procurement of the generator in advance of winter roads, with the installation and commissioning planned for 2019. The timing may be affected by the availability of winter roads prior to the 2019 commissioning.

Project timing can also be affected by weather conditions affecting the ability to safely fly in crews to the community. Under this scenario, the project timing would be shifted in the year.

Remotes operates 19 generating stations serving 21 remote communities and manages 57 generators. The timing of a generator replacement may be affected by shifting priorities for generator replacements in other communities. Big Trout Lake is one of the largest communities served by Remotes (with approximately 400 customers) and Generator A was assessed to be in very poor condition – making its replacement the top priority for generator replacements over the forecast period.

## 4.4.Cost Factors

The cost of transportation is an important factor for replacing generators in remote communities in northern Ontario. The inaccessibility of the communities makes shipping both unreliable and expensive. Labour requirements during installation, commissioning, and testing will also affect the final cost of the project depending if any issues arise.

Without the planned project, O&M costs would increase due to enhanced maintenance requirements and the increased likelihood of trouble calls to the generator.

### 4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% stated that a reliable source of electricity is a key driver to their satisfaction. Replacing this generator as per manufacturer's recommendations is an important part of maintaining the reliability of the electricity system in Big Trout Lake.

### 4.6. Leave to Construct Approval

N/A

## 5. REG Investment Costs

N/A

# Generator Overhauls

## 1. Project/Program Description

### 1.1. Current Issue

Diesel engines and their components are subject to deterioration that eventually leads to a decline in equipment performance and reliability, which increases environmental risk, safety risks, and incidence of failures. The engines are designed and manufactured to require capital overhauls at regular intervals to extend service life after a specified number of operating hours. This practice ensures the reliability of the engines and reduces the likelihood of a catastrophic failure. Medium-speed engines (1800 rpm) are overhauled after 20,000 engine-hours and low-speed engines (1200 rpm) are overhauled after 42,000 hours. Usually it is economical to overhaul an engine only twice over its lifecycle.

### 1.2. Project Scope

Four or five diesel generator engine sets are overhauled each year, depending on the size of the units. The engines are selected based on engine-hours and condition. Based on the current and forecast engine-hours, the generator units planned for overhauls will most likely be a subset of the following six:

1. Kasabonika A (1000 kW)
2. Kasabonika C (600 kW)
3. Marten Falls A (650 kW)
4. Marten Falls C (250 kW)
5. Sachigo A (635 kW)
6. Weagamow C (400 kW)

### 1.3. Main and Secondary Drivers

The driver for investments in the system renewal category, as per Table 1-1 in Remotes' DSP, is assets at the end of their service life due to failure risk. The generators in question have all reached the specified number of hours after which they are due for an overhaul according to the engine manufacturer's preventative maintenance procedures. They should therefore be rebuilt to ensure generation reliability and efficiency.

### 1.4. Performance Targets and Objectives

This investment is consistent with Remotes' asset lifecycle optimization policies and practices for diesel generators. Rebuilding generators after a specified number of hours reduces risk and ensures system reliability and generation efficiency.

System reliability is an important customer-oriented performance measure for Remotes. Remotes tracks its System Average Interruption Frequency Index ("**SAIFI**") and its System Average Interruption Duration Index ("**SAIDI**"), both of which are affected by the timely overhauls of generators. System reliability is a key driver of customer satisfaction; therefore, the investment contributes to achieving the customer satisfaction.

The implementation of this program also contributes to the achievement of the desired outcomes for generation availability through improved reliability of the generators and diesel generation efficiency through improved fuel usage.

## 1.5. Condition of Assets

Remotes prepared a forecast of the operating hours for each unit. The forecast will be compared to actual operating hours. The forecast is used to determine priorities for annual overhauls. Information on the other assets in service and seasonality compared to the size of the unit are also used to prioritize work to ensure the least disruption to community reliability.

## 1.6. Customer Impact

a) Customer profile for the community:

| Customer Class | Non Std A – Res. | Non Std A – Seas. | Non Std A – GS 1P | Non Std A – GS 3P | Street Lightning | Std A – Res. – Air | Std A – GS – Air | Total |
|---|---|---|---|---|---|---|---|---|
| **Community** | **Number of Customers** | | | | | | | |
| **Kasabonika** | 206 | - | 14 | 5 | - | 11 | 17 | **253** |
| **Marten Falls** | 76 | - | 9 | 2 | - | 8 | 13 | **108** |
| **Sachigo Lake** | 131 | - | 14 | 1 | 1 | 5 | 13 | **165** |
| **Weagamow** | 244 | - | 24 | 1 | 1 | 12 | 26 | **308** |

b) Customer impacts for each community:

The table below presents the customer impacts for each community, including the expected outage duration and frequency without the planned project. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

| Community | Customer Count | Load at Risk (kW peak) | Value of Customer Impact |
|---|---|---|---|
| **Kasabonika** | 264 | 1106 | High |
| **Marten Falls** | 113 | 494 | High |
| **Sachigo** | 170 | 718 | High |
| **Weagamow** | 311 | 1096 | High |

An unplanned outage in a community can be cleared in less than two hours if the operator can respond. Otherwise, the outage time varies depending on the nature of the underlying issue. The minimum response time is four hours to dispatch a crew to a community. An unplanned replacement may take up to six months. Marten Falls A is the largest generator in its community; the other three communities have larger generators that can serve the load.

# 2. Project/Program Justification

## 2.1. Information Used to Justify the Investment

Diesel engines and their components are subject to deterioration that negatively impacts equipment performance and system reliability over time. Maintenance and capital overhauls in accordance with manufacturer guidelines mitigate the risk of failure. Manufacturers recommend overhauling engines based on the number of operating hours to retain and extend the life of the unit. To proactively plan overhauls, Remotes forecasts the engine-hours based on historical trends. The units are prioritized for an overhaul based on the actual number of operating hours, the condition of the units, and their likelihood of failure. This review is performed by Remotes' generation staff who have reviewed test results and who perform regular maintenance of the units.

The projected engine-hours for the six engines shortlisted for an overhaul are shown below.

| | Year | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|
| **Generator** | **Speed** | **Projected Engine-hours** | | | | | |
| **Kasabonika A** | 1200 rpm | 80,400 | 86,714 | 93,029 | 99,344 | 105,659 | 111,973 |
| **Kasabonika C** | 1800 rpm | 19,898 | 21,603 | 23,309 | 25,015 | 26,721 | 28,426 |
| **Marten Falls A** | 1200 rpm | 81,172 | 84,779 | 88,385 | 91,991 | 95,597 | 99,204 |
| **Marten Falls C** | 1800 rpm | 52 | 75 | 98 | 121 | 144 | 167 |
| **Sachigo A** | 1800 rpm | 15,495 | 19,379 | 23,264 | 27,148 | 31,033 | 34,918 |
| **Weagamow C** | 1800 rpm | 16,767 | 18,615 | 20,462 | 22,309 | 24,156 | 26,004 |

## 2.2. Alternatives Evaluation

**Alternative 1: Do nothing**

For the "do nothing" option, regular generator maintenance is continued without any capital overhaul.

**Alternative 2: Generator replacement**

This alternative considers the replacement of the generator instead of the rebuild.

a) <u>Comparison of Project Alternatives</u>

In the case of the "do nothing" option, the generator is run to failure without regard for the manufacturer's recommendations. The greatest risk under this scenario is the loss of remaining life of the generator. For a medium-speed (1800 rpm) generator, an overhaul allows the generator to run for an additional 20,000 hours until its next overhaul or replacement. For a low-speed (1200 rpm) generator, an overhaul allows the generator to run for an additional 42,000 hours until its next overhaul or replacement. Without the overhaul, it is likely that the generator would require an emergency replacement before reaching its maximum number of operating hours. Replacement of the failed generator would be more expensive than the cost of an overhaul. The run to failure strategy also poses an unacceptable safety, environmental, efficiency, and reliability risk (see Section 3.1).

A planned replacement is not the optimal intervention strategy before the second overhaul is performed. None of the engines earmarked for an overhaul have been overhauled twice. The engines can be run for an additional 20,000 or 42,000 hours, at which point the need for an additional overhaul or a replacement will be assessed. The planned replacement of these engines would be about three times the cost of an overhaul and would constitute a loss of useful life. This is not the preferred alternative.

The planned project to overhaul the units is the optimal trade-off between costs and benefits and is the most economic option to extend the lives of these generators.

b) Comparison of Project Timing Alternatives

Remotes owns 57 generator units that are currently in service. If the number of overhauls is decreased each year, the overall risk of failures in at least one community would consequently increase. Based on the forecast number of operating hours, there are more generators that will require overhauls than resources to meet these guidelines. Remotes regularly monitors the generator maintenance records to determine which units are the highest priority to complete.

Remotes already checks its forecast of operating hours against its maintenance records and the results of tests on the units. If the program spending is reduced, then generation redundancy would be compromised across Remotes' service territory. Regular maintenance on the remaining generators would, therefore, also be compromised. Depending on which engines remain in service and on the season, this may necessitate rotating blackouts.

Starting a project in peak load season (midwinter) is avoided to reduce risk to other unit failures, which would run more continuous and at higher loads during this time.

c) Analysis of Project Enhancements

The scope of work does not include any project enhancements in addition to the planned overhauls.

## 2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

| | Historical Costs ($ '000) | | | | | Future Costs ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017*** | **2018** | **2019** | **2020** | **2021** | **2022** |
| Capital (Gross) | 710 | 663 | 755 | 691 | 670 | 675 | 688 | 702 | 718 | 732 |
| Removals | (58) | (66) | (75) | - | (67) | (68) | (69) | (70) | (72) | (73) |
| **Net Capital** | **652** | **597** | **680** | **691** | **603** | **608** | **619** | **632** | **646** | **659** |
| O&M | - | - | - | - | - | - | - | - | - | - |

*includes 0 months of actual expenditures

b) Start Date
April 1, 2018

c) In-Service Date
November 30, 2018

d) 2018 Test Year Expenditure Timing

| | Forecast Costs ($ '000) | | | |
|---|---|---|---|---|
| | **Q1** | **Q2** | **Q3** | **Q4** |
| Capital (Gross) | - | 225 | 225 | 225 |
| O&M | - | - | - | - |

e) Comparative Expenditure Information

Comparative expenditures for engine overhauls over the historical period are shown in the table above. The budget is based on historical trends: the average gross spending over the historical period was $698k per year and the average gross spending over the forecast period is $703k per year. The number of generators overhauled depends on the cost – determined by the speed of the unit and its size (capacity).

## 2.4. Benefits

a) Operation Efficiency and Cost Effectiveness

When generators age, they become less fuel efficient. Engine overhauls renew or extend asset life, mitigating this loss of efficiency. This also prevents premature failure of the engine and defers the need for replacement. Engine replacements are substantially costlier than overhauls, so this procedure is cost-effective.

b) Customer

This investment improves system reliability for the customers in the relevant communities.

c) Safety

Proactive rebuilding of generators mitigates the risk of an unplanned generator failure, which may pose a safety concern.

d) Cyber-Security, Privacy

This investment pertains to the generators themselves and not to its controls or communication auxiliaries.

e) Co-ordination, Interoperability

Remotes coordinates with the Band Councils concerning new investments.

f) Economic Development

The majority of Remotes customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. This investment is expected to maintain the reliability of the electrical systems and a reliable supply of electricity is good for economic growth.

g) Environment

As generators undergo operational wear-and-tear, their fuel efficiencies decrease. An engine overhaul improves the condition of the generator and mitigates the efficiency losses. Furthermore, this investment ensures the reliable operation of these generators, which ensures the PLCs can select the most fuel-efficient generators based on the load.

h) System Impacts

This investment helps maintain system performance.

# 3. Prioritization

## 3.1. Criteria for Prioritization

This program is measured against the following seven risk categories:

1. Customer/reliability
2. Regulatory relationship
3. Financial
4. Efficiency
5. Environment
6. Safety
7. Reputation

a) Customer/reliability

Based on manufacturer guidelines, the probability of increased maintenance and the risk of a catastrophic failure will increase without the planned project. Regular maintenance of the remaining generators would also be impacted, increasing the risk of community-wide outages as generators are taken out of service for maintenance. Depending on which unit failed and when a new unit could be procured and put into service, and on the season, rotating blackouts could be in place for a week or longer. Remotes does not have spare units on site in every community; therefore, the replacement unit would have to be procured and transported to the community. For the fly-in communities, this would represent an unacceptable risk to reliability as a replacement unit would need to be transported to the community. If a second unit were to fail, a community evacuation could potentially be required.

b) Regulatory

Without the planned program, safety and reliability may be compromised, which would constrain Remotes' regulatory relationship.

c) Financial

Without the planned program, additional oil changes, inspections and valve sets would still be done. Alternately, the engine may require replacement. The cost on average would be $600-$700k to replace, compared to an overhaul at approximately $200k. Any failure is treated as an emergency. Unplanned trips to the community would also be required. The remaining life of the generator would be lost and a new engine is about three (3) times more expensive than an overhaul.

d) Efficiency

Remotes' generating stations are typically designed with three generators, sized to meet load within communities. The two smaller units are normally capable of carrying the peak load in the community. This design allows for redundancy in the event of a failure. If a single generator were to fail, there would not be an outage in the community. However, there would be a loss of fuel efficiency, leading to higher volumes of fuel burnt, with higher costs and higher emissions. Depending on which generator is out of service, fuel efficiency would be affected (for example, the large unit is most efficient during peak load and is less efficient if run to meet lower loads). If Remotes' engines cannot follow load, diesel fuel consumption would increase by about 10%.

e) Environment

The reduction in generator efficiency without the engine overhaul program would increase the emissions intensity. In addition, an unplanned engine failure may create a hole in the engine block, which would leak coolant and fuel contaminants and increase the risk of fire.

f) Safety

Proper investment into diesel generators follow best practices recommended by manufacturers to ensure they operate safely. If someone is in the station when a unit fails, he or she could be struck by flying parts.

g) Reputation

Customers deserve and desire power that is good, safe, and reliable.

## 3.2. Consequences of Deferral

Remotes manages 57 engines. Reducing investment in engine overhauls would gradually lead to increased risk in terms of reliability, regulatory, financial, efficiency, environment, safety, and reputation.

## 3.3. Priority

Remotes prioritizes investments into generator overhauls based on the availability of resources. Trouble calls and operational defects always take priority over engine overhauls. This is a high priority program in the capital plan.

# 4. Execution Path

## 4.1. Implementation Plan

The work is performed between April and November to avoid a planned outage during peak load conditions in winter. The need to overhaul each unit is assessed based on the actual operating hours accrued. The timing of the overhaul is prioritized using available resources. Trouble calls and the repair of operational defects are prioritized before overhauls. Overhauls are completed by a dedicated station crew which is also responsible for the maintenance of Remotes' generators.

## 4.2. Risks and Risk Mitigation

Another risk to project completion is the availability of crew accommodation. Remotes only has lodgings for one crew in each community. Therefore, only one project can be implemented at a time in a community.

## 4.3.Timing Factors

The project plan is based on the forecast number of engine-hours for these units in 2017 and 2018, which will necessitate the overhaul. In case the actual engine-hours of the units were to differ significantly from the projection, then it may be necessary to alter the project plan in the 2018 Test Year to include generators that have reached the threshold number of engine-hours.

### 4.4. Cost Factors

The cost of a generator overhaul is largely based on the size of the generator. Although these costs are well understood and can be planned in accurately in advance, the units requiring an overhaul may change in accordance with the factors listed in Section 4.3 above, which may affect the final cost of the project.

Without the planned project, O&M costs would increase due to enhanced maintenance requirements and the increased likelihood of trouble calls to the generator.

### 4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% stated that a reliable source of electricity is a key driver to their satisfaction. Overhauling generators as per manufacturer's recommendations is an important part of maintaining the reliability of the electricity systems.

### 4.6.Leave to Construct Approval

N/A

## 5. REG Investment Costs

N/A

# Diesel Plant Civil Improvements

## 1. Project/Program Description

### 1.1. Current Issue

Diesel plant civil improvements are required to maintain the safety and operability of the diesel generating stations. In the 2018 Test Year, improvements are planned at the diesel generating stations in Kingfisher Lake and Weagamow.

### 1.2. Project Scope

This investment includes improvements of the diesel plant in Kingfisher Lake and Weagamow. The work will include DGS siding, insulation, roofing, and concrete betterment. Diesel plant civil improvements are performed every year, and the community is chosen based on assessment of relative needs.

The diesel generator station facility located in Kingfisher Lake is a manufactured steel building. The roof structure consists of steel liner panels acting as the interior ceiling and doubling as the air/vapour barrier. The roof's thermal layer is composed of fiberglass batt insulation. The roof/ceiling support consists of horizontal steel with steel Z-girts running perpendicular to the horizontal structure to support the liner panel ceiling below. The proposed project would form a tempered air space above the existing panels. In addition, proper airflow from soffit to the ridge should also be created within the new tempered air space. By providing a tempered space above the existing steel roof, any heat loss which would occur at the eave location must now be transferred through the air space before transmitting heat to the new roof panels above. By enabling proper airflow into the air space by allowing fresh cold air in from the soffit and venting out at the ridge, heat transfer through the air space to the new steel roof panels can be significantly reduced.

Similarly, Weagamow's diesel generator station is a steel manufactured building. Roof construction consists of horizontal steel liner panel acting as the ceiling and as the air/vapour barrier for the roof. The insulation in the attic space is a single batt of fiberglass insulation. In addition to the ventilation issue identified at the Kingfisher diesel generator station, Weagamow has insufficient insulation within the attic space. As there is limited space within the existing attic for placement of additional batt insulation, the existing roof panels will be removed to facilitate additional fibreglass batt insulation and creation of a tempered air space.

### 1.3. Main and Secondary Drivers

The driver for investments in the system renewal category, as per Table 1-1 in Remotes' DSP, is that assets are at the end of their service life, resulting in substandard performance. In the case of civil improvements, this refers to the condition of the generating plant building itself. Poor condition of the diesel plant causes poor working conditions for Remotes' staff and can even threaten the health and safety of staff and the general public.

## 1.4. Performance Targets and Objectives

The proposed investment would improve daily working conditions of staff and operators in Kingfisher Lake and Weagamow, as well as mitigate safety hazards that would otherwise have to be mitigated through costly workarounds. As part of its metric tracking initiatives, Remotes tracks the number of lost time injuries and the total number of recordable injuries and upgrades to the diesel plants will assist in achieving the targets for these metrics. In accordance with Remotes' asset lifecycle optimization policies and practices, the capital upgrade is the more effective method of mitigating the risk compared to costly maintenance.

## 1.5. Condition of Assets

At Kingfisher Lake, the lack of ventilated airspace at the eaves is causing ice formation at the roof edge, leading to safety risks. To date, Remotes has worked around the issue by connecting temporary ice-stops to the light gauge roof panels, but the fasteners continually pull out of the light gauge material, requiring a great deal of maintenance and compromising the effectiveness of the steel roofing panels.

In Weagamow, ventilation in the attic space is insufficient and there is no air space at the exterior wall locations due to insufficient heel height on the roof trusses. In addition, the roof panels are beginning to show signs of deterioration on the exterior.

## 1.6. Customer Impact

a) Customer profile for the community:

| Customer Class | Non Std A – Res. | Non Std A – Seas. | Non Std A – GS 1P | Non Std A – GS 3P | Street Lightning | Std A – Res. – Air | Std A – GS – Air | Total |
|---|---|---|---|---|---|---|---|---|
| **Community** | **Number of Customers** | | | | | | | |
| **Kingfisher Lake** | 108 | - | 10 | 2 | - | 4 | 17 | **141** |
| **Weagamow** | 244 | - | 24 | 1 | 1 | 12 | 26 | **308** |

b) Customer impacts for each community:

The table below presents the customer impacts for each community. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

| Community | Customer Count | Load at Risk (kW peak) | Value of Customer Impact |
|---|---|---|---|
| **Kingfisher Lake** | 141 | 649 | High |
| **Weagamow** | 308 | 1096 | High |

## 1.7. Supporting Documentation

The *Diesel Generator Station Roof Assessment Report* is attached as Appendix H to the DSP. Photos of the two stations with upgrades planned in 2018 are provided on the following pages, as excerpted from the report.

**Figure 1: Kingfisher Lake Diesel Generating Station (Exterior)**

**Figure 2: Existing Roof Insulation Thickness (Kingfisher Lake)**

**Figure 3: Roof Panel Mid-Span & Eave Support (Kingfisher Lake)**

**Figure 4: Roof Panel Peak Support (Kingfisher Lake)**

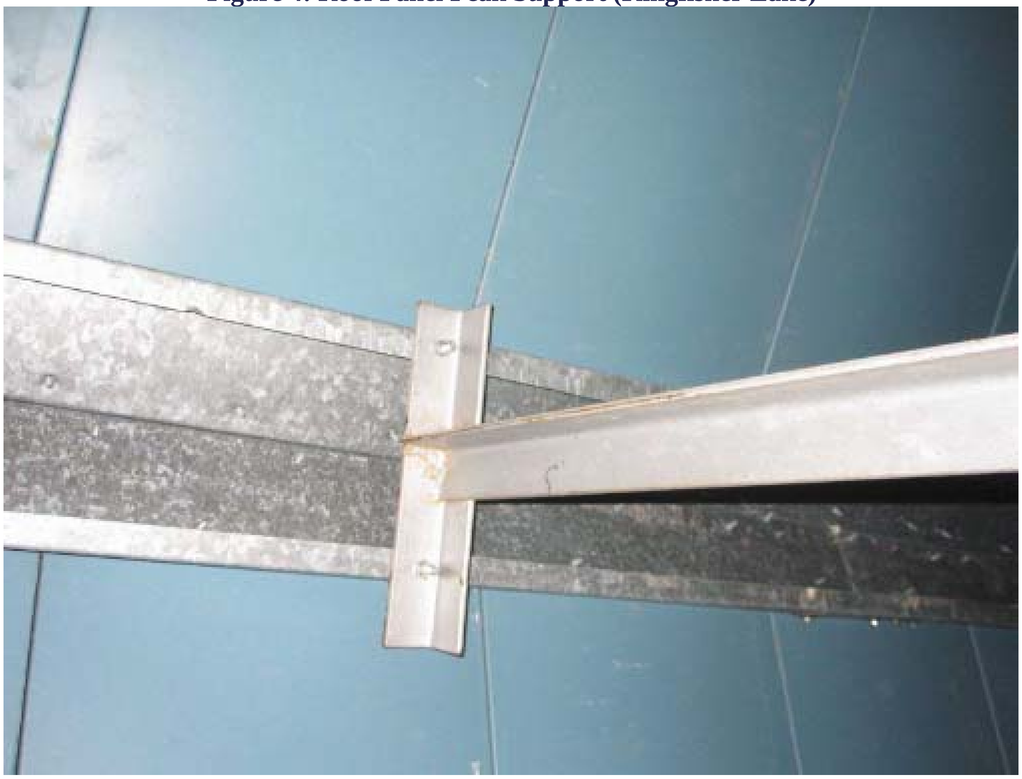


**Figure 5: Roof Panel Peak Support (Kingfisher Lake)**

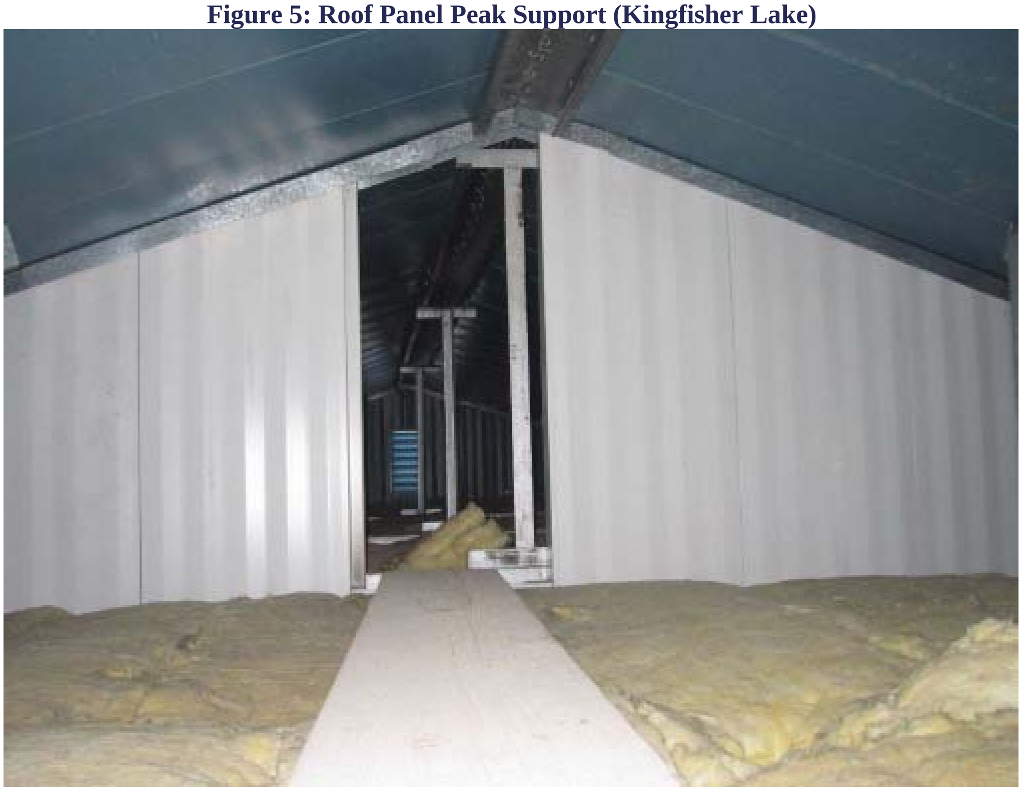


**Figure 6: Roof Framing (Weagamow)**

**Figure 7: CFC Purlins (Weagamow)**

**Figure 8: Insufficient Air Space (Weagamow)**

**Figure 9: Beginnings of Visible Ice Formation (Weagamow)**

**Figure 10: Exposed Fuel Line Tray & Visible Heat Loss (Weagamow)**

**Figure 11: Visible Heat Loss & Roof Panel Deterioration Signs (Weagamow)**

# 2. Project/Program Justification

## 2.1. Information Used to Justify the Investment

A report by FORM Architecture Engineering titled *Diesel Generator Station Roof Assessment Report & Recommendations* provides the justification for the investment. The report is included as Appendix H to the DSP.

## 2.2. Alternatives Evaluation

**Alternative 1: Do nothing**

The "do nothing" option considers no capital investment or preventative maintenance to the diesel generating stations. Staff and the operator would continue to work in the plant and the safety of these workers would be compromised.

**Alternative 2: Preventive maintenance**

The icing concerns can be temporarily mitigated using ice-stops connected to light gauge roof panels.

**Alternative 3: Build a new diesel generating station**

A new station is planned for the community; however, the timing and amount of available INAC funding is uncertain. The station must be in service and usable until a new modular unit is built. When the new station is completed, it is anticipated that most of the old plant will be used for storage. Therefore, the building will still be used and useful.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, the ice formation would pose an unacceptable safety risk at the diesel generating stations. This is not a feasible alternative.

The fasteners installed as part of the preventative maintenance option continually pull out of the light gauge material. This requires costly maintenance to ensure performance. In addition, continual re-attachment of the temporary ice-stop material provides new penetrations through the roof panels and compromises the effectiveness of the roofing material. This is not the preferred alternative.

The alternative to build a new diesel generating station would mitigate the concerns of the existing station but would cost much more than the planned site upgrade. The condition of the remainder of the diesel generating station does not warrant a complete rebuild. This is not the preferred alternative.

The planned upgrades in Kingfisher Lake and Weagamow will mitigate the safety risk of ice formation without requiring costly and ongoing maintenance over the life of the building. The planned upgrade in Weagamow will also improve the insulation to reduce the heat loss from the building. This is the preferred option, as per the recommendations of the *Diesel Generator Station Roof Assessment Report*.

b) Comparison of Project Timing Alternatives

Deferral of the project would mean that the station roofs continue to deteriorate and ice build-up would continue to put staff and operators at risk. More important, the stations where roofs are planned are all old and, at some point, maintenance to keep the integrity of the building intact is required. Deferral of these investments could result in the need for further civil work as the building envelope could be compromised.

c) Analysis of Project Enhancements

Full details of the recommended upgrades planned under this project can be found in Appendix H.

## 2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

| | Historical Costs ($ '000) | | | | | Future Costs ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
| Capital (Gross) | 133 | 412 | 250 | 211 | 344 | 346 | 353 | 360 | 368 | 376 |
| Removals | - | - | - | - | - | - | - | - | - | - |
| **Net Capital** | **133** | **412** | **250** | **211** | **344** | **346** | **353** | **360** | **368** | **376** |
| O&M | - | - | - | - | - | - | - | - | - | - |

b) Start Date
April/May 2018

c) In-Service Date
June 30 to July 30, 2018

d) Comparative Expenditure Information

| | Forecast Costs ($ '000) | | | |
|---|---|---|---|---|
| | **Q1** | **Q2** | **Q3** | **Q4** |
| Capital (Gross) | - | 173 | 173 | - |
| O&M | - | - | - | - |

e) Comparative Expenditure Information

Comparative information on expenditures for equivalent projects/activities can be found in Section 2.3(a) above. The cost of diesel plant civil improvements depends on the scope of work for each station.

## 2.4. Benefits

a) Operational Efficiency and Cost Effectiveness

As per the Comparison of Project Alternatives, the alternative to the capital upgrade is preventative maintenance to prevent ice formation at the diesel generating stations. The fasteners installed as part of the preventative maintenance option continually pull out of the light gauge material, therefore the maintenance must be performed continually. The continual reattachment of the temporary ice-stop material provides new penetrations through the roof panels and compromises the effectiveness of the roofing panels. The investment mitigates the structural compromise cost effectively without the need for continuous maintenance.

b) Customer

Customers benefits from the safety improvement in the communities. Since the investment is cost effective compared to continual maintenance over the life of the diesel generating station, ratepayers also benefit from the cost effectiveness of the investment.

c) Safety

The investment will mitigate a safety risk of ice formation at the diesel generating station.

d) Cyber-Security, Privacy

Not applicable to civil upgrades.

e) Co-ordination, Interoperability

This project applies recognized engineering principles based on a third-party report by FORM Architecture Engineering, stamped by a Professional Engineer registered in the Province of Ontario. The report has been included as Appendix H to the DSP. Remotes coordinates with the local Band Councils for upgrades in the communities.

The station in Weagamow is old and is not in good repair. INAC funding for a new plant may become available; however, the scope and timing of INAC funding is uncertain. Once funding is received it will be spread over multiple years for the entire station rebuild. In the interim, the community will continue to require reliable electricity and measures are required to mitigate the safety hazards.

f) Economic Development

The majority of Remotes customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training.

g) Environment

The additional fiberglass insulation at Weagamow diesel generating station will reduce the amount of energy lost to the environment.

h) System Impacts

Not applicable to civil upgrades.

# 3. Prioritization

## 3.1.Criteria for Prioritization

This program is measured against the following two risk categories:

1. Financial
2. Safety

a) Financial

Without the planned projects, ice barriers would need to be installed. This is a temporary fix necessitating frequent capital reinvestment. A new roof would eventually be required at Weagamow.

b) Safety

Falling ice is a serious safety risk for operators and staff entering or leaving the generation station.

### 3.2. Consequences of Deferral

If either project were deferred, falling ice would remain a safety hazard at these stations. Roofs would be subject to further deterioration. Maintenance work to install ice barriers in each of the communities would continue to be required.

### 3.3. Priority

Civil projects are a lower priority than those that affect community reliability. However, the safety of staff and station operators is also a priority.

## 4. Execution Path

### 4.1. Implementation Plan

The project includes insulation and roofing upgrades. The work will be done by experienced construction personnel familiar with building upgrades. The work will be coordinated with other work in the communities, including a planned capacity upgrade of the Weagamow generator. The generator will be procured in 2018 and installed in 2019, therefore the two projects will not interfere with one another.

### 4.2. Risks and Risk Mitigation

The biggest project risk is the use of in-house labour as the project is labor intensive. It will be managed through regular involvement and oversight by both the civil department and the project planner.

### 4.3. Timing Factors

The ability to safely fly in crews can affect the timing of this project.

### 4.4. Cost Factors

The project cost estimate is based on the expected labour hours and material costs, which can vary for civil upgrades in remote communities in northern Ontario. The net spending on the Weagamow generating station improvements depends on the capacity upgrade project in Weagamow. If the civil plant is replaced as part of the upgrade, then the cost would be recoverable through INAC.

### 4.5. Customer Preferences

Poor condition of the generating station can cause an increase in outages and reduce reliability.

### 4.6. Leave to Construct Approval

N/A

# 5. REG Investment Costs

N/A

# SCADA & PLC Replacements

## 1. Project/Program Description

### 1.1.Current Issue

This program seeks to upgrade the Supervisory Control and Data Acquisition ("**SCADA**") and Programmable Logic Controller ("**PLC**") systems deployed in the Remotes' generating stations along with telecommunications equipment used to monitor the operation of this equipment. The PLC and SCADA equipment currently in use are, on average, nearly 20 years old. New replacement parts to conduct repairs are no longer available given the models' obsolescence, while used parts are increasingly difficult to procure. Moreover, the Compact TSX PLC equipment is near its maximum memory storage capacity and lacks the spare input/output points that could enable temporary upgrades. Current site connectivity (required for remote monitoring and operation) is provided by obsolete dial-up modem technology, with significant speed and reliability implications.

### 1.2. Project Scope

The planned replacements, targeted for the 2018 Test Year include satellite or fibre optic communications equipment and SCADA upgrade at Armstrong, Gull Bay, Kingfisher Lake, Sachigo Lake, and Weagamow, along with the PLC unit upgrade at Armstrong.

### 1.3. Main and Secondary Drivers

As per Table 1-1 in Remotes' DSP, system reliability and operational efficiency are the main drivers for the planned communication, SCADA and PLC upgrades.

### 1.4. Performance Targets and Objectives

The PLC and SCADA systems are integral to efficient and reliable operation in the Remotes service territories – automation of Remotes generator equipment to follow communities' load profiles throughout the day has enabled the company to achieve a 10% improvement in fuel efficiency. Furthermore, real-time monitoring of generator station equipment permits Remotes to quickly identify station failures such as outages or fuel spills, resulting in better system reliability and environmental protection through faster issue identification and response, along with ensuing benefits to the related corporate performance measures.

### 1.5.Customer Impact

a) <u>Customer profile for the community:</u>

The following table showcases the number and rate classification of customers in the communities targeted for upgrades:

| Customer Class | Non Std A – Res. | Non Std A – Seas. | Non Std A – GS 1P | Non Std A – GS 3P | SL | Std A – Res. – Road | Std A – GS – Road | Std A – Res. – Air | Std A – GS – Air | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **Community** | | Number of Customers | | | | | | | | |
| **Armstrong** | 240 | 39 | 58 | 6 | 2 | 5 | 12 | - | - | **362** |
| **Gull Bay** | 86 | - | 8 | - | - | 3 | 9 | - | - | **106** |
| **Kingfisher Lake** | 108 | - | 10 | 2 | - | - | - | 4 | 17 | **141** |
| **Sachigo Lake** | 131 | - | 14 | 1 | 1 | - | - | 5 | 13 | **165** |
| **Weagamow** | 244 | - | 24 | 1 | 1 | - | - | 12 | 26 | **308** |

b) Customer impacts for each community:

The table below presents the customer impacts for each community, including the expected outage duration and frequency without the planned project. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50 seasonal customers

| Community | Customer Count | Load at Risk (kW peak) | Value of Customer Impact |
|---|---|---|---|
| **Armstrong** | 362 | 1035 | Medium |
| **Gull Bay** | 106 | 334 | High |
| **Kingfisher Lake** | 141 | 649 | High |
| **Sachigo Lake** | 165 | 718 | High |
| **Weagamow** | 308 | 1096 | High |

## 1.6. Supporting Documentation

Remotes is in the process of equipping all of its generating stations towards a standard equipment set-up consisting of:

- Fiber or satellite telecommunications equipment.
- M340 – BMXP342020 or M580 PLC hardware with firmware version 10.0.
- Momentum – 171-CBU-980-90 PLC hardware with firmware version 10.0.
- Small PC – SDC170 touchscreen or desktop PC IFix hardware.
- Windows 7 Pro and IFix 5.8 software with Proficy Historian

Establishing a standard equipment complement in each community is expected to simplify the maintenance, repairs/replacements, and incident response efforts throughout the Remotes' service territory, thereby positively impacting the company's servicer levels while managing the aggregate costs.

The following table summarizes the existing equipment at each generating station. The existing solutions are over 10 years old. Remaining with the current configuration will increase risk due to the lack of replacement parts and outdated software.

| Site | Telecom. | PLC | | IFix | |
|---|---|---|---|---|---|
| | | Hardware | Firmware | Hardware | Software |
| **Thunder Bay** | Fibre internet | N/A | N/A | Virtual Machine<br>Virtual Machine | Windows 7, IFix 5.8<br>Proficy Historian, Webspace |
| **Armstrong** | Dial-up | TSX Compact – PC-E984-275<br>Momentum | 2.6 SR3<br>2.6 SR3 | INX Panel PC | Windows NT4, Fix |
| **Bearskin** | Dial-up | TSX Compact – PC-E984-275<br>Momentum | 2.2 SR2<br>2.2 SR2 | INX Panel PC | Windows NT4, Fix |
| **Big Trout** | Dial-up – fibre upgrade soon | TSX Compact – PC-E984-275<br>Momentum | 2.2 SR2<br>2.2 SR2 | INX Panel PC | Windows NT4, Fix |
| **Biscotasing** | Dial-up | TSX Compact – PC-E984-275<br>Momentum – 171 CCC 760 10 & 00 | 2.2 SR2<br>2.2 SR2 | INX7000 Panel PC | Windows NT4 SP6, Fix |
| **Deer Lake** | Satellite | Quantum – 140-CPU-113-03S<br>Momentum | 2.6 SR3<br>2.6 SR3 | Desktop PC | Windows XP, IFix 3.5 |
| **Deer Lake Hydel** | Satellite | Quantum – 140-CPU-534-14 (Spare)<br>Momentum | 2.6 SR3<br>2.6 SR3 | Touch Panel PC | Windows NT4, Fix 7.0 |
| **Fort Severn** | Dial-up | TSX Compact – PC-E984-275<br>Momentum | 2.6 SR3<br>2.6 SR3 | INX6000 Panel PC | Windows NT4, Fix |
| **Gull Bay** | Dial-up | TSX Compact – PC-E984-275<br>Momentum | 2.2 SR2<br>2.2 SR2 | Desktop PC & Panel PC | Windows XP, Fix |
| **Hillsport** | Dial-up | TSX Compact – PC-E984-275<br>Momentum | 2.6 SR3<br>2.6 SR3 | INX Panel PC | Windows NT4, Fix |
| **Kasabonika** | Dial-up – fibre upgrade soon | Quantum – 140-CPU-434-12A<br>Momentum – 171-CBU-980-90 | 8.0<br>8.0 | Desktop PC & iEi Touchscreen | Windows 7, IFix 5.5 |
| **Kingfisher** | Dial-up | TSX Compact – PC-E984-275<br>Momentum – 171 CCC 760 10 | 2.6 SR3<br>2.6 SR3 | INX6000 Panel PC | Windows NT4, Fix32 V 7.0 |
| **Lansdowne** | Dial-up | TSX Compact – PC-E984-275<br>Momentum | 2.2 SR2<br>2.2 SR2 | INX Panel PC | Windows NT4, Fix |
| **Marten Falls** | Satellite | Quantum – 140-CPU-434-12 | 2.6 SR6 | Desktop PC | Windows XP Pro SP3, IFix |

| Site | Telecom. | PLC | | IFix | |
|---|---|---|---|---|---|
| | | Hardware | Firmware | Hardware | Software |
| | | Momentum – 171 CCC 760 10<br>Momentum – 171 CCC 960 30 & 10 | 2.6 SR6<br>2.6 SR6 | | 5.0 SP2 |
| **Oba** | Dial-up | TSX Compact – PC-E984-275<br>Momentum – 171 CCC 760 10 & 00 | 2.6 SR3<br>2.6 SR3 | INX7000 Panel PC | Windows NT4 SP6, Fix32 V 6.1 |
| **Sachigo** | Dial-up | TSX Compact – PC-E984-275<br>Momentum | 2.2 SR2<br>2.2 SR2 | INX Panel PC | Windows NT4, Fix |
| **Sandy Lake** | Satellite | Quantum – 140-CPU-434-12<br>Momentum | 2.6 SR3<br>2.6 SR3 | Desktop PC | Windows XP, Fix32 V 7.0 |
| **Sultan** | Dial-up | Quantum – 140-CPU-534-14<br>Momentum – 171 CCC 960 30 | 2.6 SR3<br>2.6 SR3 | Dell Optiplex GX50 | Windows NT4, Fix32 V 7.0 |
| **Wapekeka** | Dial-up – fibre upgrade soon | TSX Compact – PC-E984-275<br>Momentum | 2.6 SR3<br>2.6 SR3 | INX Panel PC | Windows NT4, Fix |
| **Weagamow** | Dial-up | TSX Compact – PC-E984-275<br>Momentum | 2.6 SR6<br>2.6 SR6 | INX Panel PC | Windows NT4, Fix |
| **Webequie** | Satellite | Quantum – 140-CPU-434-12<br>Momentum | 2.6 SR3<br>2.6 SR3 | Desktop PC | Windows XP, IFix 5.1 |

# 2. Project/Program Justification

## 2.1. Information Used to Justify the Investment

Remotes' PLC and SCADA systems were originally installed between 1998 and 2000, and vendors no longer support the existing equipment and software. In the event of failure, the Remotes personnel rely on internal expertise and available spare equipment to rectify the issues as they arise. As the existing equipment continues to age, the probability of its failure (across a variety of potential causes) continues to increase, thereby increasing the risk to continuous system operations at an acceptable standard.

## 2.2. Alternatives Evaluation

**Alternative 1: Do nothing**

The "do nothing" alternative entails no SCADA or PLC upgrades, and the current configurations are used at Remotes' substations.

**Alternative 2: SCADA and PLC replacement at another station**

This alternative assumes that SCADA and PLC upgrades at other stations than those planned in the 2018 Test Year where these upgrades could ostensibly be justified.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, functionality and system capability are expected to be significantly reduced going forward. This is not the preferred alternative.

To compare various stations for upgrades, the following metrics were considered:

- Remoteness: distance from the service centre (Thunder Bay).
- Population of the community.
- Availability of auxiliary power for the communication, SCADA, and PLC systems.
- Reliability of existing communication systems.

The annual project priorities are based on the worst performing station infrastructure. Each metric above was given a composite index rating on the basis of the above criteria. The outcome of the rankings was used to prioritize the stations. The following table summarizes the results of the analysis.

| Community | Remoteness | Population | Aux. Power | Comm. Reliability | Total |
|---|---|---|---|---|---|
| Big Trout | 17 | 19 | 0 | 2 | 38 |
| Sandy Lake | 15 | 20 | 1 | 1 | 37 |
| Fort Severn | 20 | 10 | 0 | 5 | 35 |
| Bearskin | 19 | 13 | 0 | 2 | 34 |
| Sachigo | 18 | 12 | 0 | 2 | 32 |
| Wapekeka | 16 | 11 | 0 | 5 | 32 |
| Deer Lake | 14 | 15 | 1 | 1 | 31 |
| Kasabonika | 13 | 16 | 0 | 2 | 31 |
| Weagamow | 12 | 17 | 0 | 2 | 31 |
| Deer Lake Hydel | 14 | 15 | 0 | 1 | 30 |
| Armstrong | 3 | 18 | 0 | 4 | 25 |
| Webequie | 10 | 14 | 0 | 1 | 25 |
| Kingfisher | 11 | 9 | 0 | 2 | 22 |
| Marten Falls | 8 | 8 | 1 | 1 | 18 |
| Lansdowne | 9 | 6 | 0 | 2 | 17 |
| Bisco | 7 | 5 | 0 | 2 | 14 |
| Sultan | 6 | 4 | 0 | 2 | 12 |
| Gull Bay | 2 | 7 | 0 | 2 | 11 |
| Hillsport | 4 | 3 | 0 | 2 | 9 |
| Oba | 5 | 2 | 0 | 2 | 9 |

b) Comparison of Technically-Feasible Alternatives

Communications infrastructure alternatives include fibre, satellite, and dial-up internet. Fibre is the most reliable and flexible technology, since it is available consistently and offers the most bandwidth. Satellite offers intermittent but successful communications. Dial-up is the least effective, since there is limited bandwidth and availability is affected by power outages in other communities. The preferred communications infrastructure was selected based on available technologies within the communities, with the elimination of dial-up considered the highest priority. In the fly-in communities, there is only a single provider of fibre infrastructure. Fibre infrastructure is installed where available, otherwise satellite communications is used. Canadian satellite communication providers are limited to a sole source tailoring to the industrial environment with a proven track record.

The SCADA and PLC technology was chosen for compatibility with existing systems to reduce training costs and changes to existing infrastructure.

## 2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

| | Historical Costs ($ '000) | | | | | Future Costs ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017* | 2018 | 2019 | 2020 | 2021 | 2022 |
| Capital (Gross) | - | - | - | - | 413 | 505 | 726 | 675 | 391 | 353 |
| Removals | - | - | - | - | - | - | - | - | - | - |
| **Net Capital** | **-** | **-** | **-** | **-** | **413** | **505** | **726** | **675** | **391** | **353** |
| O&M | - | - | - | - | - | - | - | - | - | - |

*0 months of actual expenditures included in 2017

b) Start Date
January 1, 2018

c) In-Service Date
December 31, 2018

d) 2018 Test Year Expenditure Timing

| | Forecast Costs ($ '000) | | | |
|---|---|---|---|---|
| | Q1 | Q2 | Q3 | Q4 |
| Capital (Gross) | 126.25 | 126.25 | 126.25 | 126.25 |
| O&M | - | - | - | - |

e) Comparative Expenditure Information

There are no equivalent historical projects of this nature.

## 2.4. Benefits

a) Operational Efficiency and Cost Effectiveness

The SCADA and PLC systems are key to ensuring the operational efficiency of the generators.

b) Customer

This investment affects system reliability, by allowing real-time monitoring of the station.

c) Safety

A functional and up-to-date SCADA system allows Remotes' personnel to accurately assess any issue which may arise, thus improving employee and public safety.

d) Cyber-Security, Privacy

In accordance with the NIST Guide to Industrial Control Systems Security, the planned upgrade includes restrictions of physical access to the station, PLC monitoring to detect security events, a demilitarized zone ("**DMZ**") network architecture, and restrictions of unauthorized remote access.

e) Co-ordination, Interoperability

Remotes coordinates with Band Councils concerning new investments. The investment enables future operational requirements at the generating stations in question.

Interoperability and compatibility are incorporated into the design.

f) Economic Development

Most of Remotes' customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training.

g) Environment

The SCADA and PLC upgrades are expected to improve the company's fuel efficiency and enhanced ability to quickly identify fuel spills.

# 3. Prioritization

## 3.1. Criteria for Prioritization

This program is measured against the following four risk categories:

1. Customer/reliability
2. Financial
3. Efficiency
4. Environment

a) Customer/reliability

Currently, a SCADA system breakdown requires manual agent operation of the generating equipment. Outage information is no longer available, leading to longer outages. SCADA information is necessary for troubleshooting the cause of generation station outages. When operator intervention is required, communication is improved with SCADA information.

Outages related to a PLC failure can normally be cleared in less than an hour. The frequency of outages increases due to PLC failures. Lack of connectivity reduces knowledge of outage cause, reducing ability to troubleshoot problems remotely. Also, customers may need to call before an outage is detected.

b) Financial

The PLC controls many plant interactions, including general selection and power output. Operators can run the plant manually; however, this is difficult and inefficient. Troubleshooting will likely be necessary to return the plant to operation. PLC troubleshooting would require a flight ($5000) and labour hours.

c) Efficiency

The estimated benefit of the overall SCADA and PLC system is a 10% increase in fuel efficiency. Fuel tanks are monitored via the SCADA system. Spill alarms are also connected to the SCADA system. Response to spill events could be delayed, increasing the scope and cost of rectification efforts.

d) Environment

Absent the planned program, generation emissions would be higher due to the reduced generator efficiency. A SCADA malfunction may results in a longer response time in case of a spill, which increases the risk of contaminants leaking into the environment.

### 3.2.Consequences of Deferral

Automation of the plants and an ability to monitor performance is critical to investigate the cause of outages. Without reliable communications, SCADA, and PLC systems, Remotes would be unable to perform preventative maintenance, troubleshooting, and rapid event notification. Furthermore, plant operation will change from automated to operator manual operation.

### 3.3. Priority

The project has been staged over several years. Improving the SCADA system provides necessary access to operational information to improve and maintain current operations. Failures of the PLC system require manual intervention, which can require flights and labour hours.

## 4. Execution Path

### 4.1. Implementation Plan

This investment consists of a three-part process:

1. Upgrade Communications

   Addition of satellite or fibre wide-network connectivity. Fibre is the preferred choice due to the speed and reliability advantage over satellite. Where fibre is not available, satellite can be incorporated.

2. Upgrade SCADA hardware and software

   To take full advantage of the upgraded communications, the SCADA systems need to handle the increased bandwidth. New hardware and software will be procured, configured, installed, and commissioned. Cyber-security, compatibility, and capacity will be incorporated in the design.

3. Upgrade PLC hardware and software

   To combat the memory capacity and the lack of input/output expandability as well as utilizing new Ethernet communication, PLC hardware replacement will occur. Each upgraded PLC will mirror the existing software.

The projects are also coordinated with other work planned at the generating stations. In 2018 civil plant upgrades are planned at the Weagamow and Kingfisher Lake diesel generating stations.

### 4.2.Risks and Risk Mitigation

The greatest risks to completing this program as planned relate to timing and cost factors, as described below.

### 4.3. Timing Factors

The ability to safely fly in crews are can affect the timing of this investment. To mitigate this risk, Remotes can work around the weather to complete the work earlier or later in the year.

### 4.4. Cost Factors

For complex system upgrades such as SCADA, PLC, and communication upgrades, the largest factor affecting the final cost of the project is cost of labour. The number of personnel depends upon the testing and commissioning requirements of each system to ensure compatibility among the various components. Since 2017 is the first year of this program, these costs are not well known. Controllable costs are minimized through extensive vendor participation prior to project rollout. By using similar systems for the different generating stations, Remotes also reduces the installation, testing, and commissioning costs.

### 4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% of respondents stated that a reliable source of electricity is a key driver to their satisfaction. Modern engines have critical engine data available to be interfaced with the PLC and SCADA, providing the company with a better picture of the state of the plant. This information enables the maintenance staff to analyze and solve problems without undue delay, thereby managing the number of equipment interruptions.

Environmental protection is also important to Remotes' customers as identified in Remotes' 2016 Customer Workshop. This project improves diesel fuel efficiency, reducing the environmental impact of the diesel generation.

### 4.6.Regional Electricity Infrastructure Requirements

Given the nature of Remotes' operations, this project is not driven by any regional electricity infrastructure requirements. The 2016 Order-in-Council by the Minister of Energy identified 16 communities which are expected to be connected to new transmission lines passing through northern Ontario, including Sachigo Lake, Kingfisher Lake, and North Caribou Lake (Weagamow). The Remote Community Connection Plan is still in its draft form until further community consultation is performed and the anticipated connection date of this community is not known.

### 4.7.Incorporation of Advanced Technology

The project incorporates advanced SCADA, communications, and PLC technology.

### 4.8. Leave to Construct Approval

N/A

## 5. REG Investment Costs

N/A

# Big Trout Lake and Wapekeka Connection and Upgrade

## 1. Project/Program Description

### 1.1. Current Issue

The peak station load at Big Trout Lake reached 1395 kW in 2015, which exceeds the 1360-kW connection limit. The community of Wapekeka currently does not have new customer connection restrictions in place, but the peak load has reached 643 kW, which represents 74% of the station rating. Given that the Order-in-Council by the Minister of Energy has identified these two communities to be connected to new transmission lines at an undecided date in the future, Remotes' customers have requested funding through INAC to connect these two communities and perform upgrades at the generating stations to facilitate the connection, in the manner discussed in this document. The planned of the two communities is expected to increase the combined system capacity.

### 1.2. Project Scope

The scope of work includes an upgrade of the generation stations in Big Trout Lake and Wapekeka and a new 22-km, 25-kV overhead line linking the communities of Kitchenuhmaykoosib Inninuwug (Big Trout Lake) and Wapekeka First Nations, that is planned to address the load growth in both communities. Planning and design work for this project commenced in 2015.

The unit chosen to be replaced is the smallest generating unit in the combined generating station, namely the C unit in Wapekeka with 410 kW of capacity, as it will be too small to carry the lowest load level of the combined communities. It will be exchanged for a 1500-kW unit, increasing the combined station rating to 3765 kW. Upon replacement, the original generating unit would go back into inventory to be deployed in another community.

The planned scope of work would increase the station transformation capacity in each community to 3000 kW. Once construction is complete, this project would remove new customer connection restrictions in the Kitchenuhmaykoosib Inninuwug community, and enable unconstrained customer connections in both communities for five to ten years. The planned work is 100% recoverable through funding agreements with the First Nations and INAC.

The distribution system equipment in question was procured earlier in 2017. Generation equipment is planned to be purchased in 2018 and 2019. Modifications to the Wapekeka Generation Station are planned to commence in 2018. Big Trout Lake generating station modifications are planned for 2019. Testing and integration would ensue prior to putting the unit into service in 2020.

Additionally, 67.5 kW of community-owned solar, requested by customers and to be placed on related non-Standard A accounts, is planned as part of the project.

### 1.3. Main and Secondary Drivers

The driver for generator upgrade investments, as per Table 1-1 of Remotes' DSP, is system capacity constraints (i.e. expected changes in load that will constrain the ability to the system to provide consistent delivery). The peak load in Big Trout Lake has surpassed the connection limit (85% of the station rating) and should therefore be upgraded immediately.

Big Trout Lake and Wapekeka are 22 km apart and connected by a road. Connecting the two generating stations would decrease the combined peak load and thus result in a more efficient system. Furthermore, the connection between these two communities will be necessary once the new transmission lines reach the communities.

## 1.4. Performance Targets and Objectives

The investment affects a number of performance targets listed in Remotes' DSP. The connection of the two communities would improve the ability to supply power from either diesel generating station under contingency situations, reducing the frequency and duration of outages in both communities. As discussed in Section 2.3.1.1 of Remotes' DSP, system reliability is a key driver to customer satisfaction. The proposed upgrade of Wapekeka C would reduce the probability of its unplanned failure and thus improve reliability and generator availability. By connecting the two distribution systems, the load can be managed more efficiently using the Programmable Logic Controller (PLC) technology to improve diesel generation efficiency.

The proposed project is expected improve operational efficiency and cost effectiveness. For a project this size, 375,000 litres of additional fuel tanks would normally be required and purchased. In this case, only 150,000 litres of new fuel tanks are planned to be purchased in Wapekeka as part of this project. Both First Nations currently have fuel storage at their respective airports. To make up for the required fuel storage, each First Nation has agreed to sell fuel to Remotes and to dedicate a tank to Remotes.

A notable drawback of these improvements is an increase distribution losses are expected to increase with the addition of the new line (line losses are proportional to distance). However, the benefits associated with the improvements to system operability and reliability offered by the proposed investments exceed the impact of the associated increase in losses.

Remotes manages its diesel generating stations by limiting the peak load at the station to 85% of the station's rating (known as the connection limit). By connecting the two communities and upgrading unit C at Wapekeka, the system constraints will be removed and the planning objectives will be improved in both communities in the future.

## 1.5.Customer Impact

a) Customer profile for the community:

| Customer Class | Non Std A – Res. | Non Std A – Seas. | Non Std A – GS 1P | Non Std A – GS 3P | Street Lightning | Std A – Res. – Air | Std A – GS – Air | Total |
|---|---|---|---|---|---|---|---|---|
| **Community** | **Number of Customers** | | | | | | | |
| **Big Trout Lake** | 301 | - | 30 | 6 | - | 10 | 50 | **397** |
| **Wapekeka** | 114 | - | 10 | 1 | - | 5 | 20 | **150** |

b) Customer impacts for each community:

The table below presents the customer impacts for each community. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10% and 50% seasonal customers.
- Low – greater than 50% seasonal customers

| Community | Customer Count | Load at Risk (kW peak) | Value of Customer Impact |
|---|---|---|---|
| **Big Trout Lake** | 397 | 1395 | High |
| **Wapekeka** | 150 | 643 | High |

# 2. Project/Program Justification

## 2.1. Information Used to Justify the Investment

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load has surpassed 85% of the station rating. The forecast peak load in Big Trout Lake and Wapekeka for the years 2017 through 2022 are listed in kW in the table below. The forecast is based on the actual peak load observed in 2016.

| Community | Connection Limit (kW) | Peak Load Forecast (kW) | | | | | |
|---|---|---|---|---|---|---|---|
| | | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **Big Trout Lake** | 1360 | 1381 | 1436 | 1493 | 1553 | 1615 | 1680 |
| **Wapekeka** | 735 | 651 | 670 | 691 | 711 | 733 | 755 |
| **Combined** | N/A | **2032** | **2106** | **2184** | **2264** | **2348** | **2435** |

## 2.2. Alternatives Evaluation

**Alternative 1: Do nothing**

The “do nothing” option entails the case where no upgrades are made at either station and the new distribution line is not built.

**Alternative 2: Upgrade of both systems without new connection**

This option considers the ability to upgrade both systems individually

a) Comparison of Project Alternatives

In the case of the “do nothing” option, Remotes would have to ignore the request of its customers for this project to proceed, contrary to the company’s values and operating principles. Furthermore, under the “do nothing” scenario, connection restrictions would persist indefinitely in Big Trout Lake, and materialize in Wapekeka in the next five years. These considerations render the “do nothing” option suboptimal.

In the case of the second alternative – upgrading both systems individually without the new connection, the upgrade in Wapekeka could be deferred until 2022 or later based on the projected load growth in the community. Instead, the project would upgrade one of the generators in Big Trout Lake immediately, which would be costlier than upgrading the smaller generator in Wapekeka. The isolated systems are less robust when responding to contingency situations than a combined system. Furthermore, the new distribution line will be necessary once the anticipated new transmission connection project reaches the communities. Therefore, Alternative 2 is also suboptimal given its inferior cost effectiveness in light of the anticipated developments over the assets' lifetimes.

Accordingly, the proposed option represents an optimal trade-off between benefits and costs. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes, which is usually the most cost-effective option.

b) Comparison of Technically-Feasible Alternatives

The option to build an underground distribution line rather than the overhead distribution line connecting the two communities is a technically-feasible alternative to this project. The cost of construction for an underground distribution line in an area of mostly-frozen soil is much more expensive than an overhead build; therefore, an overhead line was planned.

For a project this size, 375,000 litres of additional fuel tanks would normally be required and purchased. In this case, only 150,000 litres of new fuel tanks are planned to be purchased in Wapekeka as part of this project. Both First Nations currently have fuel storage at their respective airports. To make up for the required fuel storage, each First Nation has agreed to sell fuel to Remotes and to dedicate a tank to Remotes.

## 2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

| | Historical Costs ($ '000) | | | | | Future Costs ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017* | 2018 | 2019 | 2020 | 2021 | 2022 |
| Capital (Gross) | - | - | 8 | 137 | 996 | 2,149 | 3,252 | 1,364 | - | - |
| Contributions | - | - | (8) | (123) | (896) | (1,934) | (2,927) | (1,228) | - | - |
| Removals | - | - | - | (14) | (100) | (215) | (325) | (136) | - | - |
| **Net Capital** | - | - | - | - | - | - | - | - | - | - |
| O&M | - | - | - | - | - | - | - | - | - | - |

*0 months of actual expenditures included in 2017

b) Start Date
Distribution material purchased in 2017
Generation purchases in 2018 and 2019

c) In-Service Date
June 2020

d) 2018 Test Year Expenditure Timing

| | Forecast Costs ($ '000) | | | |
|---|---|---|---|---|
| | Q1 | Q2 | Q3 | Q4 |
| Capital (Gross) | 537.25 | 537.25 | 537.25 | 537.25 |
| O&M | - | - | - | - |

e) Comparative Expenditure Information

Remotes has never previously tied stations together in the proposed manner – the project was conceived in response to limited availability of INAC funds and the goal of the communities to connect new customers in the near term.

## 2.4. Benefits

a) Operational Efficiency and Cost Effectiveness

By providing a solution that relieves connection constraints in Big Trout Lake and alleviates medium-term capacity concerns in Wapekeka without requiring a generator upgrade in Big Trout Lake, this project is expected to enhance the operational efficiency and cost effectiveness. Notwithstanding the near-term objectives, the proposed distribution line will be required once the communities are connected to the transmission system and, therefore, represents a cost-effective means of relieving the capacity issue and improving reliability of supply in both communities in the interim. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

b) Customer

This project was initiated by Remotes' customers, who benefit through relief of capacity constraints and the improved reliability of the new system. The First Nations will also benefit from increased economic activity associated with the sale of fuel to Remotes and from the installation of community-owned solar generation.

c) Safety

The investment is not expected to negatively impact health and safety protections and performance, as all applicable construction safety standards and operating clearance requirements will be met. The new distribution line will be constructed using Remotes' standards for distribution line construction, compliant with *O. Reg. 22/04*.

d) Cyber-Security, Privacy

In accordance with the NIST Guide to Industrial Control Systems Security, the planned upgrade includes restrictions of physical access to the station, PLC monitoring to detect security events, a demilitarized zone ("**DMZ**") network architecture, and restrictions of unauthorized remote access.

e) Co-ordination, Interoperability

As with all generation upgrade projects, Remotes is working closely with the First Nation communities through the funding allocation and design approval process. When a community's load levels begin to approach their connection limits, Remotes collaborates with the community to identify possible solutions to alleviate the capacity constraints. If a generator upgrade project is required, customers requests the project from Remotes, who works with the community to secure the requisite INAC funding. Under the terms of the electrification agreements, INAC is responsible for funding generation capital upgrades associated with load growth in First Nation communities served by Remotes. The funding must be requested by the communities, but Remotes also works closely with INAC in relation these projects. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

Kitchenuhmaykoosib Inninuwug and Wapekeka First Nations are both anticipating connection to new transmission lines that will reach the area. This has been coordinated into the project plan, since the new distribution line will be required once the transmission lines reach these communities.

f) Economic Development

Most of Remotes' customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. This investment will relieve system capacity constraints in two communities and build a more robust electrical system for the communities, which is conducive to economic growth. The communities will also benefit from the ability to sell fuel and electricity to Remotes and from the ability to perform forestry work that will be required on the line.

g) Environment

Part of the project scope will replace a generator in Wapekeka and newer generators are more fuel efficient. The project will also upgrade the transformation at both diesel generating stations and the new transformers will meet the latest standards in energy efficiency. In addition, planned community-owned solar generation is expected to reduce environmental impacts.

# 3. Prioritization

This is a non-discretionary project, since it is requested by customers and funded by INAC. The project takes priority over discretionary projects/programs.

# 4. Execution Path

## 4.1. Implementation Plan

The program is planned to proceed over six years. It commenced in 2015 and will finish in 2020. Design and material procurement (poles, cable, station transformers, switchgear and building extension) of distribution and generation equipment will take place in 2018. Installation and commissioning of equipment will then be performed in 2019 and 2020. The generating station work will be done by a dedicated station crew, whereas line construction is expected to be tendered by the First Nation and INAC.

This project will be coordinated with other work planned in the communities, including generator replacements in Big Trout Lake from 2018 to 2020. Wherever possible, station crew utilization will be optimized between the two projects to reduce costs.

## 4.2. Risks and Risk Mitigation

The primary risk factor underlying this project and other generator upgrades is funding from INAC. On a number of past occasions, INAC was unable to support projects due to a lack of funds in light of competing priorities. Without the funding from INAC, Remotes does not have the means to recover the costs for this project and the project would not proceed. To mitigate this risk, Remotes works closely with the communities it serves and with INAC to ensure sufficient funds are available and approved to carry out the work.

Another risk to project completion is the ability to transport heavy electrical equipment to the sites, which requires use of winter roads. To mitigate this risk, the generator and transformers are procured in advance to prepare for transportation. In case an entire season passes without safe winter roads, the project may require deferral. Remotes has the option of hiring specialized aircraft to deliver the equipment if the risk of project deferral is greater than the increased transportation cost.

Remotes has lodgings for only one crew in each community. Therefore, a risk to project completion as planned includes the availability of accommodation for crews to perform work on the generation and distribution systems as part of this project, as well as emergency work that comes up throughout the year. Remotes mitigates this risk through careful project planning and execution. Remotes also has the option to locate crews in both communities (Big Trout Lake and Wapekeka) and to rent temporary accommodation if necessary.

Line construction is expected to be tendered by the First Nation and INAC and is, therefore, outside of Remotes' control.

## 4.3. Timing Factors

Winter road availability and the ability to safely fly in crews are factors that may affect the timing of this investment. Should this occur, the project may be deferred due to transportation or INAC funding delays, which Remotes attempts to are mitigate through project planning and coordination. Besides these factors, the project is customer-initiated and externally-funded and, therefore, takes priority over discretionary projects/programs.

## 4.4. Cost Factors

A large part of the final cost of this project will be transportation cost. The access to communities in question makes shipping both difficult to coordinate and expensive.

## 4.5.Customer Preferences

This project was initiated by Remotes' customers. As identified in Section 2.2.1.1 of Remotes' DSP, customers prioritize renewable energy. As such, the customer-requested scope includes 67.5 kW of community-owned solar generation.

## 4.6.Regional Electricity Infrastructure Requirements

The 2016 Order-in-Council by the Minister of Energy identified 16 communities which will be connected to new transmission lines passing through northern Ontario, including Kitchenuhmaykoosib Inninuwug (Big Trout Lake) and Wapekeka. The Remote Community Connection Plan is still in its draft form until further community consultation is performed and the anticipated connection dates of these communities are not known. In anticipation of the new transmission lines, the new distribution line is being constructed as an integrated, cost-effective approach to increase the capacity of both communities, as well as improving the robustness of the electricity supply. The new distribution line will be required to connect the communities to the new transmission line

### 4.7. Incorporation of Advanced Technology

N/A

### 4.8. Leave to Construct Approval

N/A

## 5. REG Investment Costs

N/A

# Sandy Lake Upgrade

## 1. Project/Program Description

### 1.1. Current Issue

The peak station load at Sandy Lake reached 2576 kW in 2013, nearing its connection limit of 2593 kW or 85% of the station capacity (3050 kW). Based on the current loading levels, the peak load is forecast to exceed the connection limit by 2018. Therefore, Remotes' customers have requested funding through INAC to upgrade the generating station capacity in Sandy Lake. The timing of the generation investment depends on INAC approval for the capital dollars that is presently outstanding. For planning purposes, Remotes' anticipates that the required INAC investment will be made in time to enable continued community growth (that is, 2018). Given that the investment constitutes contributed capital, there is no impact to Remotes' rate base.

### 1.2. Project Scope

There are currently four low-speed (1200-rpm) diesel generators in Sandy Lake. G1 and G2 each have a rated capacity of 1250 kW, G3 is rated 1500 kW, and G4 is rated 1000 kW. The G1, G2, and G4 units have all been in service since 2008, whereas G3 was installed in 2013. For the upgrade, the unit with the lowest capacity, namely G4, was chosen to be exchanged for a 1500 kW unit, increasing the station's aggregate rating to 3300 kW. The chosen generator has operated for the most engine-hours of the four generators.

The existing transformation capacity is sufficient to serve the load. The existing station building and generator rooms were designed to accommodate incremental community load growth and, as such, do not require any facilities expansion investments accommodate the new generator. Some modifications to the controls may be required as part of this project.

### 1.3. Main and Secondary Drivers

The driver for generator upgrade investments, as per Table 1-1 in the DSP, is system capacity constraints (i.e. expected changes in load that will constrain the ability to the system to provide consistent delivery). Sandy Lake's peak load is forecast to exceed the station's connection limit in 2018 and as such, requires an upgrade to enable continued load growth. This forecast is based on historical data that has determined the future annual load increase in Sandy Lake to be around 2.5%.

### 1.4. Performance Targets and Objectives

Remotes manages its diesel generating stations by limiting the peak load at the station to 85% of the station's rating before commencing the analytical work and engagements underlying potential expansion planning. By upgrading the G4 unit at Sandy Lake, the system constraints would be relieved.

The proposed investment would also positively affect several performance targets listed in Remotes' DSP. The upgrade of Sandy Lake G4 would reduce the probability of its unplanned failure and thus improve reliability and generator availability. By replacing the old generator with a new one that meets the latest energy efficiency standards, both diesel generation efficiency and carbon emission intensity would be positively affected.

## 1.5. Customer Impact

a) Customer profile for the community:

| Customer Class | Non Std A – Res. | Non Std A – Seas. | Non Std A – GS 1P | Non Std A – GS 3P | Street Lightning | Std A – Res. – Air | Std A – GS – Air | Total |
|---|---|---|---|---|---|---|---|---|
| **Community** | **Number of Customers** | | | | | | | |
| **Sandy Lake** | 440 | - | 29 | 3 | 1 | 21 | 26 | **520** |

b) Customer impacts for the community:

The table below presents the customer impacts in Sandy Lake. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

| Community | Customer Count | Load at Risk (kW peak) | Value of Customer Impact |
|---|---|---|---|
| **Sandy Lake** | 520 | 2576 | High |

# 2. Project/Program Justification

## 2.1. Information Used to Justify the Investment

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load has surpassed 85% of the station rating. The forecast peak load in Sandy Lake for the years 2017 through 2022 is shown below in kW. The forecast is based on the 2016 actual peak load.

| Community | Connection Limit (kW) | Peak Load Forecast (kW) | | | | | |
|---|---|---|---|---|---|---|---|
| | | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
| **Sandy Lake** | 2593 | 2535 | 2598 | 2663 | 2730 | 2798 | 2868 |

Since the load is anticipated to reach the connection limit in 2018, the station should be upgraded around that time to avoid connection restrictions.

## 2.2. Alternatives Evaluation

**Alternative 1: Do nothing**

Given the nature of the Remotes' service territory and the ensuing mode of operation, the "do nothing" option considers the case where no upgrade is made at the station.

**Alternative 2: New hydroelectric generation**

This alternative considers the option of the Sandy Lake First Nation developing a new hydro-electric generating facility (the "**Duck River Dam**") to relieve system capacity.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, Remotes would have to de-prioritize the request from its customers for this project to proceed (at least for a certain period of time), contrary to Remotes' values. Furthermore, connection restrictions are expected to occur in Sandy Lake in the next two years. This is not the preferred option.

The Sandy Lake First Nation is interested in developing the Duck River Dam; however, they have not yet been able to secure approvals from the province or the federal government to develop this project and are not expecting to resolve this issue within the timeline when the anticipated connection constraints would materialize. Accordingly, the project timelines would not address the short-term supply needs of the community. This is not the preferred alternative

The proposed project is the preferred alternative. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes, which is usually the most cost-effective option.

b) Comparison of Technically-Feasible Alternatives

The generator selected for the upgrade at Sandy Lake is both the smallest and has run for the most hours. Therefore, the upgrade of this particular unit is optimal from within the range of available options of proactively addressing the impending capacity shortages. The existing transformation at the generating station is sufficient to meet the capacity needs. Some modifications to the controls may be required as part of this project.

Rather than requesting an increase to tank storage, Remotes expects to purchase more fuel from the Sandy Lake Tank Farm.

## 2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

| | Historical Costs ($ '000) | | | | | Future Costs ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017*** | **2018** | **2019** | **2020** | **2021** | **2022** |
| Capital | - | - | - | - | - | 367 | 881 | 1,311 | - | - |
| Contributions | - | - | - | - | - | (330) | (793) | (1,180) | - | - |
| Removals | - | - | - | - | - | (37) | (88) | (131) | - | - |
| **Net Capital** | - | - | - | - | - | - | - | - | - | - |
| O&M | - | - | - | - | - | - | - | - | - | - |

*0 months of actual expenditures included in 2017

b) Start Date
Design in Q3 of 2018
Purchase engine in 2019
Transport by winter road in March 2020

c) In-Service Date
July 31, 2020

d) 2018 Test Year Expenditure Timing

| | Forecast Costs ($ '000) | | | |
|---|---|---|---|---|
| | Q1 | Q2 | Q3 | Q4 |
| Capital (Gross) | - | - | 183.5 | 183.5 |
| O&M | - | - | - | - |

e) Comparative Expenditure Information

The planned total cost of this investment is $2,559,000, spread over three years. In order to compare the cost to other station upgrade investments, cost per kW has to be considered. The new unit has 1500 kW capacity, rendering the cost per kW at $1,706.

A station upgrade was done in Deer Lake in 2016, where a new 1200-rpm generator unit with capacity 1500 kW was installed at the total cost of $2,306,368 and per-kW cost of was $1,536. The expenditures for this investment are generally consistent to the investment in Deer Lake. The observed cost differences can mostly be attributed to transportation and labour costs. Some of the First Nation communities are less accessible than others due to isolation and lack of year-round roads.

## 2.4. Benefits

a) Operation Efficiency and Cost Effectiveness

The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes, which is usually the most cost-effective option.

b) Customer

This project was initiated by Remotes' customers, who benefit through relief of capacity constraints.

c) Safety

The investment will replace an old generator, which will reduce the probability of an unplanned failure.

d) Cyber-Security, Privacy

All upgrades to generator PLCs and related infrastructure meet the latest cyber-security standards.

e) Co-ordination, Interoperability

As with all generation upgrade projects, Remotes is working closely with the First Nation communities through the funding and approval process. When a community's loading levels begin to approach its rated connection limits, Remotes collaborates with the community to identify possible solutions to alleviate the capacity constraints. If a generator upgrade project is determined required, the customer requests the company to undertake the work, and Remotes works with the community to secure INAC funding for the project. Under the terms of the electrification agreements, INAC is responsible for funding generation capital upgrades associated with load growth in First Nation communities served by Remotes. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

The community of Sandy Lake is anticipating connection to new transmission lines that will reach the community at an undetermined date. The Remote Community Connection Plan is still in its draft form until further community consultations are completed. Since connection constraints are anticipated beginning in 2018, the upgrade project is proposed to proceed.

f) Economic Development

The majority of Remotes customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. This investment will relieve system capacity constraints in Sandy Lake, which is conducive to economic growth.

g) Environment

The new generator unit will meet the latest standards in emissions and fuel efficiency.

# 3. Prioritization

This is a non-discretionary project, since it is requested by customers and funded by INAC. The project takes priority over discretionary projects/programs.

# 4. Execution Path

## 4.1. Implementation Plan

The project is planned over a three-year period. Design of upgrade will take place in 2018, procurement and installation in 2019, and completion of construction and commissioning in 2020. The work will be done by a dedicated station crew. This project will be coordinated with other work planned in Sandy Lake.

## 4.2. Risks and Risk Mitigation

The primary concern for this project and other generator upgrades is funding from INAC. In the past, INAC was unable to consistently support projects due to funding constraints in certain years. Absent the funding from INAC, Remotes does not have the means to recover the costs for this project and the project can not proceed until the situation is resolved. To mitigate this risk, Remotes works closely with the communities it serves and INAC to ensure sufficient funds are available and approved to carry out the work.

Another risk to project completion is the ability to transport heavy electrical equipment to the sites, which requires winter road access. To mitigate this risk, the generator is procured in advance to be ready for transportation in short order when the suitable weather conditions materialize. In case of an entire season passing without safe winter road conditions, the project may need to be deferred. Remotes has the option to hire a specialized aircraft to deliver the equipment if the risk of project deferral is greater than the increased transportation cost.

Finally, Remotes has lodgings for only one crew in each community. Therefore, a risk to the completion of the project as planned is the availability of accommodation for crews to perform work on the generating station as part of this project and emergency work that comes up throughout the year. Remotes mitigates this risk through careful project planning and execution. Remotes also can rent temporary accommodation in necessary.

### 4.3. Timing Factors

Winter road availability and the ability to safely fly in crews are factors that can affect the timing of this investment. This project may be deferred due to transportation or INAC funding delays, which are mitigated through project planning and coordination. Besides these factors, the project is customer-initiated, non-discretionary and externally-funded, and therefore takes priority over discretionary projects/programs.

### 4.4. Cost Factors

A large part of the final cost of this project will be transportation cost. The inaccessibility of the First Nation communities makes shipping both unreliable and expensive. Another important factor that may affect the final cost of the project is labour cost. Controllable costs are minimized by using experienced station crews and selecting the most cost-effective transportation option.

### 4.5. Customer Preferences

This project was initiated by Remotes' customers.

### 4.6.Regional Electricity Infrastructure Requirements

This project does not directly arise from Regional Electricity Infrastructure Requirements. The 2016 Order-in-Council by the Minister of Energy identified 16 communities which will be connected to new transmission lines passing through northern Ontario, including Sandy Lake. The Remote Community Connection Plan is still in its draft form until further community consultation is performed and a federal/provincial funding agreement is in place. The anticipated connection dates of these communities are not known. The peak load in Sandy Lake is forecast to reach the connection limit in 2018; therefore, the project is proposed to move ahead subject to the availability of INAC funding.

### 4.7.Incorporation of Advanced Technology

N/A

### 4.8. Leave to Construct Approval

N/A

## 5. REG Investment Costs

N/A

# Weagamow DGS Upgrade

## 1. Project/Program Description

### 1.1. Current Issue

The peak load in North Caribou First Nation (Weagamow) reached 1096 kW in 2013, which is over ninety percent (90%) the station's connection limit of 1211 kW. An interim station upgrade was performed in 2016 to help address capacity constraints in the short term. However, the peak load is forecast to reach the technical connection limit in 2019, necessitating a larger upgrade to ensure connection capacity availability over the longer term. Accordingly, Remotes' customers have requested funding through INAC to upgrade the generating station capacity in Weagamow.

### 1.2. Project Scope

Subject to the availability and amount of INAC funding approved, the Weagamow upgrade would replace all four generators comprising the community's current generating station. Weagamow unit A was installed in 1996 and is rated 600 kW. Unit B was upgraded in 2016 from 250 kW to 725 kW capacity. Unit C was installed in 2008 with 400 kW capacity. The 1-MW D unit is owned by the North Caribou First Nation. The three units owned by Remotes are all medium speed (1800 rpm). The unit owned by the North Caribou First Nation is low speed (1200 rpm). The four units would be replaced with four units with an upgraded total station capacity of 2 MW. The existing generators owned by Remotes will be returned to inventory.

The proposed upgrade also includes construction of a larger facility to host the generating equipment, to address the spatial restrictions that characterizing the current facility, which complicate the tasks of generator maintenance and introduce potential safety risks for the company's staff.

### 1.3. Main and Secondary Drivers

As per Table 1-1 in the DSP, the key driver for the proposed generator upgrade investments is addressing System Capacity constraints (i.e. expected changes in load that will constrain the ability of the system to provide requisite output under peak conditions). Weagamow's peak load is forecast to exceed the station's connection limit in 2019, necessitating the upgrade work.

The condition of the station and reliability concerns are the secondary drivers for the upgrade. The existing building is too small to house all the generators creating restricted workspaces when engine repair or maintenance is required. Meanwhile, the condition of the D unit places reliability within the community at risk since the unit has experienced several prolonged outages in the past and is operated by the North Caribou Lake First Nations on a run-to-failure basis.

### 1.4. Performance Targets and Objectives

Remotes manages its diesel generating station by limiting the peak load at the station 85% of the station's rating. This threshold allows for consumption growth as existing customers connect more devices to the grid without compromising the ability to supply power during peak load. The proposed generator upgrade at Weagamow would relieve the system constraints.

The investment would also affect several performance targets listed in Remotes' DSP. The upgrade of the generator would reduce the probability of its unplanned failure, thereby improving reliability and generator availability. Based on Remotes' customer engagement efforts described in Section 2.3.1.1 of the DSP, reliability is a key driver for customer satisfaction. By replacing old generators with new ones that meet the latest energy efficiency standards, both diesel generation efficiency and carbon emission intensity would be improved. New generators are approximately 10% more efficient than in-service units.

## 1.5. Customer Impact

a) Customer profile for the community:

| Customer Class | Non Std A – Res. | Non Std A – Seas. | Non Std A – GS 1P | Non Std A – GS 3P | Street Lightning | Std A – Res. – Air | Std A – GS – Air | Total |
|---|---|---|---|---|---|---|---|---|
| **Community** | **Number of Customers** | | | | | | | |
| **Weagamow** | 244 | - | 24 | 1 | 1 | 12 | 26 | 308 |

b) Customer impacts for the community:

The table below presents the customer impacts for North Caribou Lake (Weagamow). The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10% and 50% seasonal customers.
- Low – greater than 50% seasonal customers

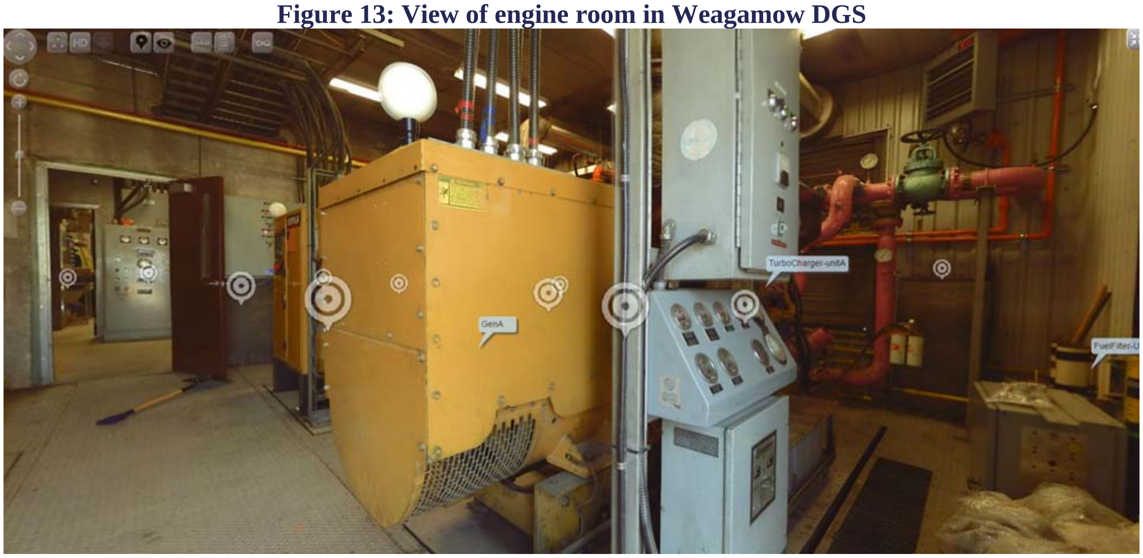
| Community | Customer Count | Load at Risk (kW peak) | Value of Customer Impact |
|---|---|---|---|
| **Weagamow** | 308 | 1096 | High |

## 1.6. Supporting Documentation

Figures 1 and 2 depict the generator rooms in Weagamow DGS. As can be seen from the pictures, the facility's size relative to the size and configuration of the generator equipment it hosts, results in significant spatial restrictions that complicate the task of servicing the equipment. The 725-kW B unit was put into service in 2013 in response to reliability concerns of the D unit and the First Nation would not permit expansion of the existing site, resulting in the present-day constraints.

**Figure 12: Close-up of engine in Weagamow DGS**

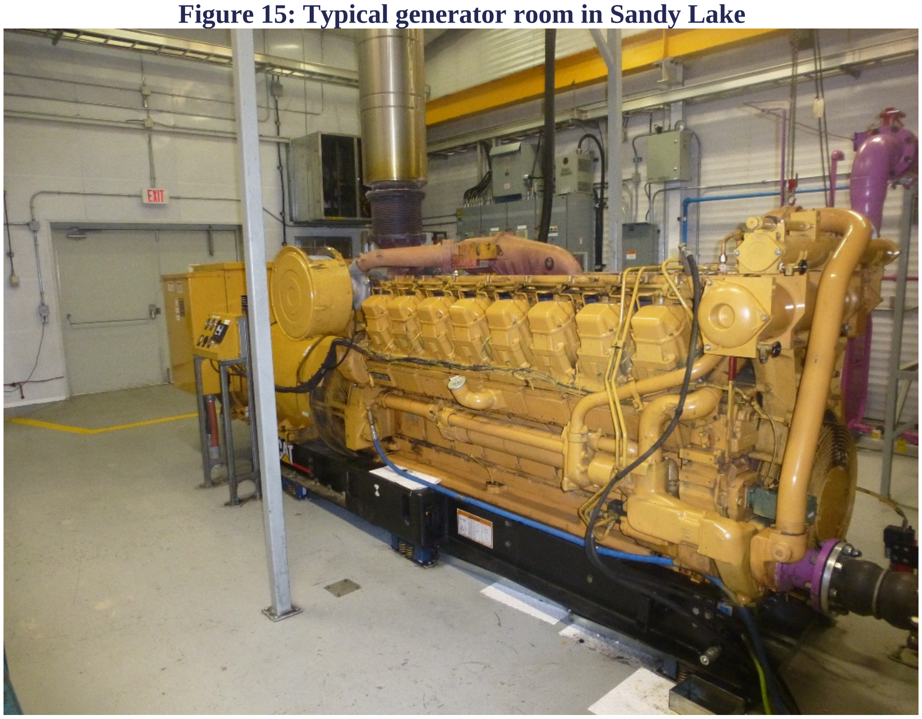

**Figure 13: View of engine room in Weagamow DGS**




For comparison, Figures 3 and 4 depict the generator rooms in Deer Lake and Sandy Lake, which are of standard sizes and each contain just one (1) engine, providing sufficient space for servicing the equipment.

**Figure 14: Typical generator room in Deer Lake**


**Figure 15: Typical generator room in Sandy Lake**



# 2. Project/Program Justification

## 2.1. Information Used to Justify the Investment

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load surpasses 85% of the station rating. Since Weagamow's load is anticipated to reach the connection limit in 2019, the station upgrade is being proposed to avoid any connection restrictions. The forecast peak load in Weagamow for the years 2017 through 2022 is shown below. This forecast is based on historical data that has determined the future annual load increase in Weagamow to be around three per cent. Beyond the community's internal growth projections, the magnitude of the forecast load growth is also a function of a planned completion of an all-season road to the community in 2017.

| Community | Connection Limit (kW) | Peak Load Forecast (kW) | | | | | |
|---|---|---|---|---|---|---|---|
| | | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **Weagamow** | 1105 | 1062 | 1094 | 1127 | 1160 | 1195 | 1231 |

The spatial restrictions and condition of the station facility itself are also significant drivers for the project. The existing building is too small to house all the generators. In stations where engines are larger than 200 kW, each engine is normally located in a separate room so that work can be done without the risk of permanent hearing damage to operators. In Weagamow, the 600-kW and 400-kW units are housed in the same room (see Figure 2) creating significant spatial restrictions that affect the manner in which work has to be performed (by extension, affecting execution efficiency and employee safety). Presently, spare engine parts must be moved to a temporary location to enable work. Moreover, the 600-kW unit is old and cannot be replaced if it were to fail, since new 600-kW units are too large to fit into the existing room in the station. Furthermore, the station has a wood floor, presenting an unacceptable environmental risk in the event of a fuel spill.

The D unit is stored in a trailer on the property that has reached end-of-life and is too small for maintenance on the unit to be conducted safely. The D unit is operated by Remotes and integrated into the supply needs of the community, but maintenance is paid for under an agreement with the unit's owner – the North Caribou First Nation. Under the terms of the agreement, maintenance by Remotes on the D unit is limited to oil changes and visual inspections. Consequently, the D unit's condition is not maintained with the same rigour as assets subject to Remotes' regular asset management process.

The condition of the D unit puts reliability in the community at risk as the unit is run to failure. For example, in September 2012, the D unit failed. While INAC and the First Nation worked to replace the D unit with a temporary unit, electricity was supplied by the 600-kW engine, along with one of the smaller engines. In November of that year, rotating blackouts were required due to failures of both smaller engines. Both smaller units were returned to service in late December. In January 2013, the 600-kW unit, which had been operating throughout the previous year's emergency conditions, failed. Rotating blackouts were avoided due to the community's conservation efforts while the 600-kW unit was out of service and being repaired. The community secured a 725-kW unit which was put into service in January 2013 until the equipment supplier could complete a major overhaul on the D unit. The temporary 725-kW unit was put into service as the B unit in 2016. Once the D unit is replaced, it will be owned and operated by Remotes and will be maintained as a normal part of Remotes' business. INAC has not yet approved funding for the project.

## 2.2. Alternatives Evaluation

**Alternative 1: Do nothing**

The "do nothing" option entails the case where no upgrade is made at the station.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, Remotes would have to defer addressing the request of its customers for this project to proceed, which is contrary to Remotes' values, and would create connection capacity restrictions within the next three years. This is not the preferred option.

The proposed facility rebuilds and generator replacement project is the preferred alternative. Generally, upgrades are required as community demand increases to ensure Remotes has enough capacity to reliably meet the needs of its customers.

b) Comparison of Technically-Feasible Alternatives

The preferred alternative is to design and build a modular station building that would house four generators. The modular units would be constructed off site. A larger modular unit assembled off site and transported to the community would house each of the units into a larger station. The existing 725-kW generating units will be repurposed, but the existing 600-V alternator will be replaced with a 4160-V alternator. Three new 4160-V generating units will be procured, including two units rated 1500 kW each and one unit other rated 725 kW. As station capacity increases, the size of the 600-V switchgear and cabling becomes too large to accommodate. The 4160-V switchgear bus and cabling is much smaller. The community is expected to be connected to an all-season road by the fall of 2017; therefore, additional on-site fuel storage is not required or requested as part of this project.

Given the uncertainty of INAC funding, Remotes must consider alternatives to downscale the project while addressing the key drivers. Accordingly, Remotes has considered a partial upgrade, including a new standalone trailer to house the First Nation-owned generator if the desired level of funding is not available. The priority will be to replace the First Nations' unit first, based on its condition, followed by the 600-kW unit, and then the 400-kW unit.

Remotes also considered a more conventional station building upgrade, where the First Nation manages the project and the station construction work is contracted out to a third party. Conventional upgrades, wherein most of the construction is completed on site, are costlier than using modular units. As the community is planning an all-season road that is expected to be in place by the fall of 2017, a modular design with completed manufacturing off-site is possible, less costly, and more time efficient. As such, it is a practical alternative given that INAC has limited funds.

The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

## 2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

| | Historical Costs ($ '000) | | | | | Future Costs ($ '000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017* | 2018 | 2019 | 2020 | 2021 | 2022 |
| Capital (Gross) | - | - | 14 | 1,816 | 1,485 | 2,832 | 1,993 | - | - | - |
| Contributions | - | - | (13) | (1,634) | (1,336) | (2,549) | (1,794) | - | - | - |
| Removals | - | - | (1) | (182) | (149) | (283) | (199) | - | - | - |
| **Net Capital** | - | - | - | - | - | - | - | - | - | - |
| O&M | - | - | - | - | - | - | - | - | - | - |

b) Start Date

Procurement in 2018
Construction in 2019

c) In-Service Date

Fall 2019

d) 2018 Test Year Expenditure Timing

| | Forecast Costs ($ '000) | | | |
|---|---|---|---|---|
| | Q1 | Q2 | Q3 | Q4 |
| Capital (Gross) | 708 | 708 | 708 | 708 |
| O&M | - | - | - | - |

e) Comparative Expenditure Information

The plant in Webequie, which includes three generators and a combined station capacity of one MW, was built by a third-party contractor in 2008, at an estimated cost of approximately $16M. The proposal in Weagamow is to design and build a modular 2-MW plant at a cost of under $10M.

## 2.4. Benefits

a) Operation Efficiency and Cost Effectiveness

The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes, which is usually the most cost-effective option. The proposed modular design is more cost-effective than a traditional substation rebuild. The existing generators will be returned to inventory.

b) Customer

This project was initiated by Remotes' customers. The project simultaneously addresses forecast connection constraints in the community and historical reliability concerns of the D unit. Customers benefit from improved electricity availability.

c) Safety

Alleviating the spatial restrictions of the generator building would enable Remotes staff to conduct regular wok activities in a safer manner.

d) Cyber-Security, Privacy

In accordance with the NIST Guide to Industrial Control Systems Security, the planned upgrade includes restrictions of physical access to the station, PLC monitoring to detect security events, a demilitarized zone ("**DMZ**") network architecture, and restrictions of unauthorized remote access.

e) Co-ordination, Interoperability

As with all generation upgrade projects, Remotes is working closely with the First Nation communities through the funding and approval process. When a community's load begins to approach its connection limit, Remotes collaborates with the community to identify possible solutions to alleviate the capacity constraints. If a generator upgrade project is determined to be required, the customer formally requests Remotes to undertake the project, and Remotes works with the community to secure INAC funding for the project. Under the terms of the electrification agreements, INAC is responsible for funding generation capital upgrades associated with load growth in First Nation communities served by Remotes. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

The community of Weagamow is anticipating connection to new transmission lines that will reach the community at an undetermined date. The Remote Community Connection Plan is still in its draft form until further community consultations are completed. The likely timeline for grid connection is between 2027 and 2037. Since connection constraints are anticipated beginning in 2018, the upgrade project will proceed.

f) Economic Development

Most of Remotes' customers are First Nations, and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. This investment will relieve system capacity constraints in Weagamow, which is conducive to economic growth.

g) Environment

The new generator unit will meet the latest standards in emissions and fuel efficiency.

# 3. Prioritization

This is a non-discretionary project, since it is requested by customers and funded by INAC. The project takes priority over discretionary projects/programs.

# 4. Execution Path

## 4.1. Implementation Plan

Procurement of generators, building, and transportation of generators to Weagamow is planned to take place in 2018. Assembly of the building modules and installation of the generators would then be completed in 2019. The work will be done by a dedicated station crew. This project will be coordinated with other work planned in Weagamow, including a civil plant improvement (a separate project) in 2018.

## 4.2. Risks and Risk Mitigation

The primary risk factor for this project and other generator upgrades is funding from INAC, the levels of which have fluctuated in the past, depending on considerations outside of Remote's control. Absent the funding from INAC, Remotes does not have the means to recover the costs for this project and the project would not proceed. To mitigate this risk, Remotes works closely with the communities it serves and with INAC to ensure sufficient funds are available and approved to carry out the work. Based on the approved funding levels, the scope of work may change. The proposed modular station design is the optimal investment plan, but a partial rebuild can be completed to meet the supply needs of the community with limited funding.

Another risk to project completion is the ability to transport heavy electrical equipment to the sites, which requires the completion of an all-season road. Remotes expects the all-season road to this community to be completed in 2017. If this is not the case, then the costs and timing of the project will change.

Remotes has lodgings for only one crew in each community. Therefore, a risk to the completion of the project as planned is the availability of accommodation for crews to perform work on the generating station as part of this project, relative to emergency work that comes up throughout the year. Remotes mitigates this risk through careful project planning and execution. Remotes also can rent temporary accommodation if necessary.

## 4.3. Timing Factors

If the completion of an all-season road to the community is delayed, then the construction of a modular station would be delayed. This project may be deferred due to transportation or INAC funding delays, which are mitigated through project planning and coordination. Besides these factors, the project is customer-initiated and externally-funded and, therefore, takes priority over discretionary projects/programs.

## 4.4. Cost Factors

A large part of the final cost of this project will be transportation cost. The remoteness of the First Nation communities makes crew transportation expensive. Another important factor that may affect the final cost of the project is labour cost. Controllable costs are minimized by using experienced station crews and selecting the most cost-effective transportation option.

## 4.5. Customer Preferences

This project was initiated by Remotes' customers, the North Caribou Lake First Nation, who will have the final say in the technical design of the project.

## 4.6.Regional Electricity Infrastructure Requirements

This project does not directly arise from Regional Electricity Infrastructure Requirements. The 2016 Order-in-Council by the Minister of Energy identified 16 communities which will be connected to new transmission lines passing through northern Ontario, including North Caribou Lake

(Weagamow). The Remote Community Connection Plan is still in its draft form until further community consultation is performed and the anticipated connection dates of these communities are not known. The peak load in Weagamow is forecast to reach the connection limit in 2019; therefore, the project will proceed. The project plan accounts for the anticipated future connection in this community and tank storage upgrades have been foregone as a more near-term approach due to the long-term uncertainties.

### 4.7.Incorporation of Advanced Technology

N/A

### 4.8. Leave to Construct Approval

N/A

## 5. REG Investment Costs

N/A

# Appendix B: North of Dryden IRRP

# NORTH OF DRYDEN
# INTEGRATED REGIONAL RESOURCE PLAN

Part of the Northwest Ontario Planning Region | January 27, 2015

ieso
Independent Electri i

**Explanatory Note Regarding January 1, 2015 OPA-IESO Merger**

On January 1, 2015, the Ontario Power Authority (OPA) merged with the Independent Electricity System Operator (IESO) to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

This report was largely completed prior to January 1, 2015. Any mention of the activities performed by the former OPA or the former IESO in this report refers collectively to the new IESO.

## Contents

## Table of Figures

**Summary of Plan Highlights**

- Drivers for increased electricity demand in the areas surrounding Red Lake, Pickle Lake and Ring of Fire include *connecting remote First Nation communities and growth in the mining sector*.

- The OPA recommends a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake and upgrades to existing lines between Dryden and Red Lake for immediate implementation to address near- and medium- term needs for the Pickle Lake and Red Lake areas.

- Incremental longer term solutions to supply Ring of Fire and Red Lake are not required at this time. Longer term options will be re-evaluated in the next planning cycle (1-5 years).

- Options to supply the Ring of Fire include transmission utilizing an East-West or North South corridor, or on-site generation. East-West and North-South transmission options are comparable in cost under the high demand scenario and the potential need for a transmission line should be considered in the planning of a common infrastructure corridor to the Ring of Fire.

- Long-term options for the Red Lake area include local gas generation or new transmission.

## Summary of Updates from August 2013 draft IRRP

- Revised demand forecast used different methodology, includes updated data and is represented by three scenarios – reference, high and low; August 2013 draft included high and low scenarios, but did not include a reference scenario.
- Revised demand forecast indicates relatively higher forecasted demand in the Pickle Lake subsystem, and relatively lower forecasted demand in the Red Lake subsystem than in the August 2013 draft.
- Recommendation is for new 230 kV line to Pickle Lake in this version; voltage recommendation was not specified in the August 2013 draft.
- Recommended line upgrades from Dryden to Red Lake are expected to be sufficient to the end of the planning period for the reference and low forecast scenarios, and to 2030 for the high forecast scenario. The August 2013 draft indicated that the upgrades may be insufficient in the medium-term for the high scenario.
- Recommendation to discuss reactive services of Manitou Falls GS with OPG, as per OPG's written submission.
- Revised economic analysis methodology – refer to Appendices 10.6, 10.7, and 10.8 for details.

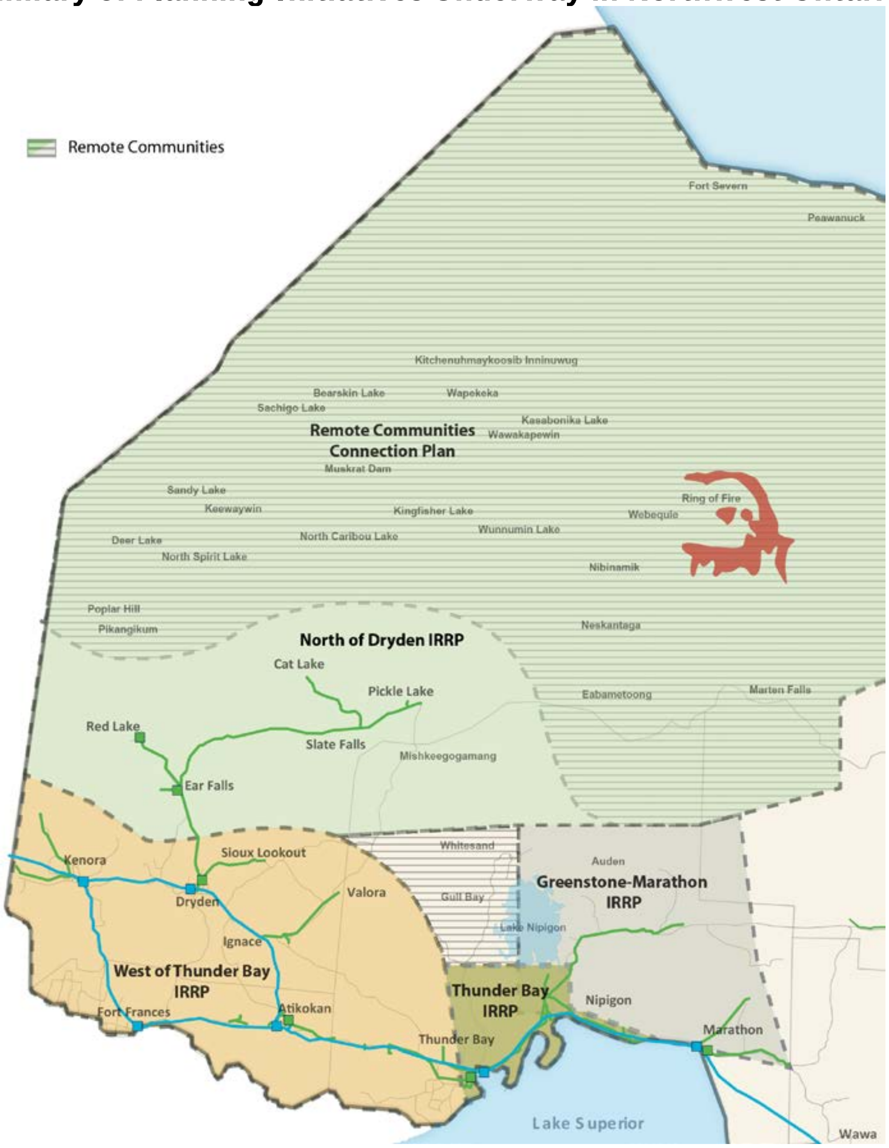
# 1 EXECUTIVE SUMMARY

## Context and Purpose

The purpose of the North of Dryden Integrated Regional Resource Plan (“regional plan”, “North of Dryden IRRP”, or “IRRP”) is to identify the near-term and medium- to long-term electricity supply needs of the area and assess options that are available to address the needs in a timely, reliable and cost-effective manner. The IRRP is intended to provide the overall planning context to address regional supply adequacy and reliability needs.

The North of Dryden IRRP is one of several electricity planning initiatives that the the Ontario Power Authority (“OPA”) is undertaking for the Northwest Ontario region. Figure 1 identifies the IRRP initiatives currently being undertaken by OPA in the Northwest Ontario region. The North of Dryden IRRP accounts for the demand requirements in the North of Dryden sub-region. This includes requirements at Pickle Lake and Red Lake related to the connection of the 21 remote First Nation communities (“remote communities”) that are economic to connect, as outlined in the Remote Community Connection Plan as well as new mining developments forecasted in the area. It also coordinates with the West of Thunder Bay IRRP, ensuring that the West of Thunder Bay transmission system is able to accommodate the expected growth north of Dryden. The North of Dryden IRRP will also coordinate options related to supply to the Ring of Fire with the Greenstone-Marathon IRRP.

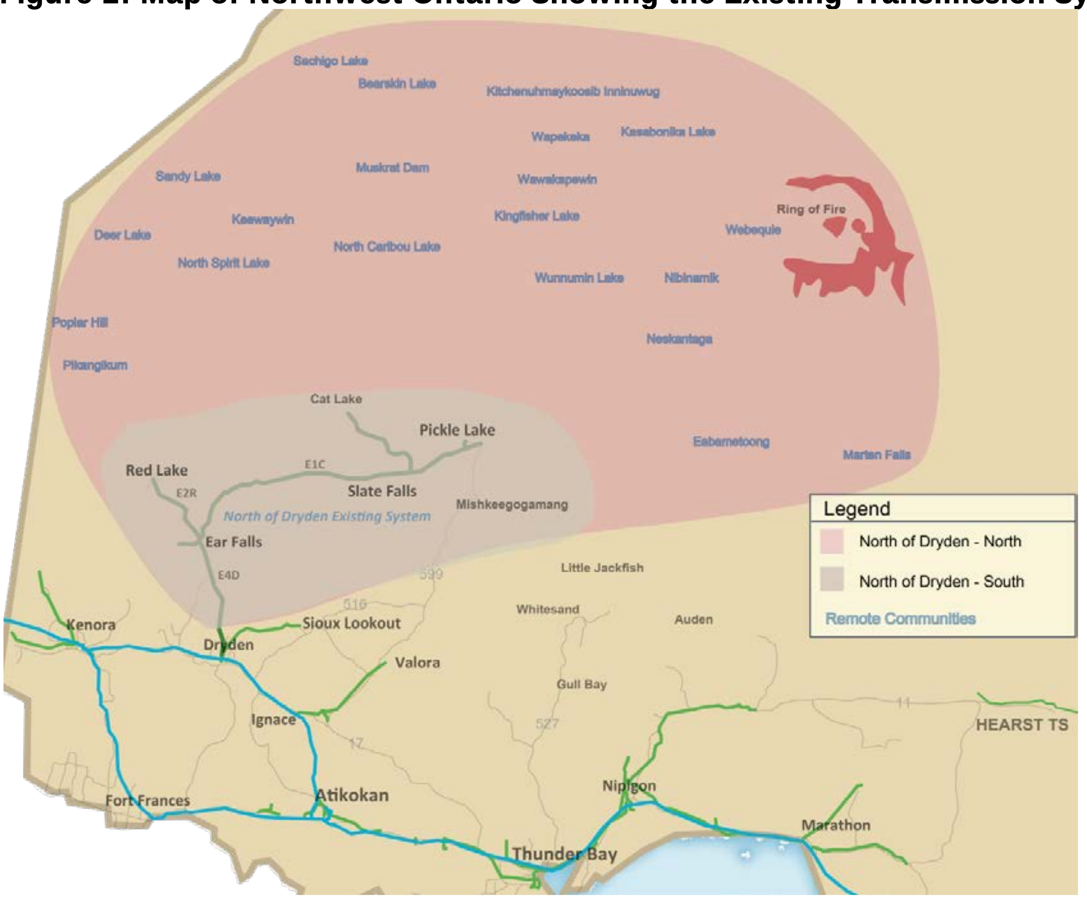
**Figure 1: Summary of Planning Initiatives Underway in Northwest Ontario**




The North of Dryden sub-region is contained within First Nation Treaty areas 3, 5, 9 and the Robinson-Superior Treaty area. It also includes portions of Region 1 and Region 2 of the Métis Nation of Ontario ("MNO"). The southern portion of the sub-region (shown in Figure 2) is currently served by Ontario's transmission grid and is bounded by Dryden to the southwest, Red Lake to the northwest and Pickle Lake to the northeast. Existing mining activity is primarily located in this southern portion of the North of Dryden sub-region and is largely focused around the towns of Ear Falls, Red Lake and Pickle Lake. The northern portion of the North of Dryden sub-region (shown in Figure 2) contains the

21 remote First Nation communities which are economic to connect, one operating mine, and the mine development area known as the Ring of Fire. At present, only one mine north of Pickle Lake is connected to the transmission grid through a privately owned transmission line.

**Figure 2: Map of Northwest Ontario Showing the Existing Transmission System**




The North of Dryden sub-region is forecast to experience some of the highest growth in electrical demand in Ontario. Currently the electricity transmission system serving the area is at capacity and is unable to accommodate demand growth.

Mining sector expansion is the primary driver of electricity demand growth in the area; through the expansion of existing mines and the development of new mines, as well as growth in the industries and communities that support the mining sector. Remote communities in the North of Dryden sub-region are currently supplied by diesel generation, however the draft Remote Community Connection Plan[1] developed jointly by the remote communities and the OPA indicates that there is an economic case for connecting the majority of these communities to Ontario's transmission system. The Remote Community Connection Plan is the OPA's primary planning document for these communities, however, the connection would put additional demand requirements on the local transmission system in the areas of Red Lake and Pickle Lake, which is considered in this IRRP.

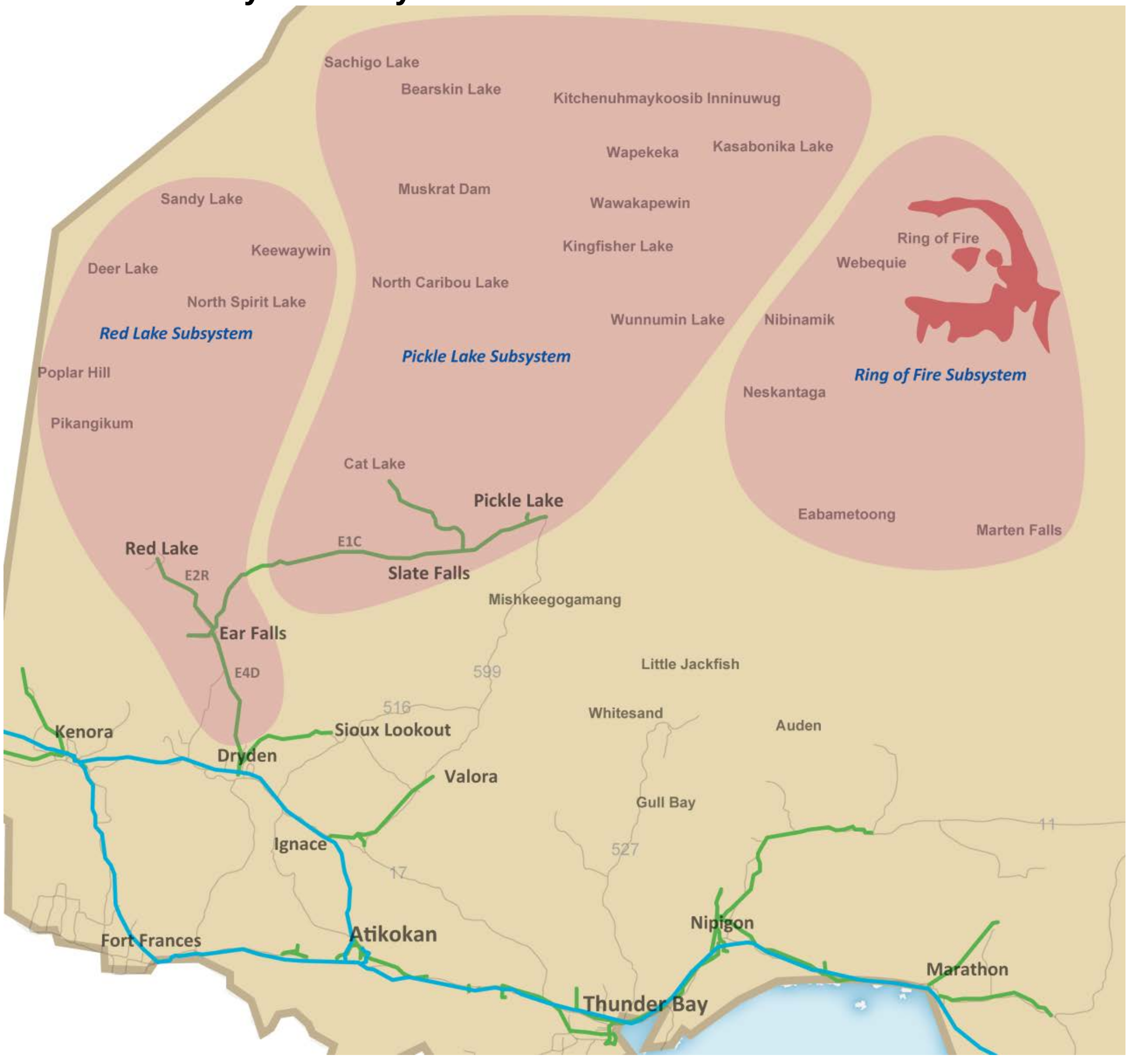
**Need Identification**

Over the past decade, the annual electricity demand growth in the North of Dryden sub-region has averaged about 1.9%. Growth plans of existing and future customers that are expected to be supplied from the local transmission system indicate that there will be a significant increase in electricity demand over the next 20 or more years.

For study purposes, the area has been segmented into three subsystems generally surrounding Red Lake, Pickle Lake and the Ring of Fire.

[1] A report entitled "Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario" was developed by the Northwest Ontario First Nations Transmission Planning Committee and the OPA. The document can be found at this website: http://www.powerauthority.on.ca/sites/default/files/planning/OPA-technical-report-2014-08-21.pdf

**Figure 3: North of Dryden Subsystems**




Where growth in electricity demand identified in these subsystems cannot be met by the existing system, technically feasible conservation, local generation, and transmission options are identified and compared based on their ability to cost effectively meet the needs.

The OPA produced high and low forecast scenarios to capture the range of variability in future electrical demand and a reference forecast to reflect a likely scenario of future demand based on the information available at the time.

This regional plan has identified that there is a near-term (2014 to 2018) need for additional Load Meeting Capability[2] ("LMC") in the transmission system currently serving the Red Lake and Pickle Lake subsystems. The regional plan has also identified that the majority of the forecasted growth is expected to occur during the medium term between 2019 and 2023. This is the period when remote communities and new mines are expected to develop and connect to the transmission system. The long term is characterized by steadily increasing demand over the remainder of the planning period (to 2033). The need for incremental LMC by subsystem is summarized in Table 1 below.

**Table 1: Incremental Capacity Needs by Subsystem**

| **Sub-system** | **Near-term Capacity Needs (Present to 2018 in MW)** | | | **Medium-term Capacity Needs (2019-2023 in MW)** | | | **Long-term Capacity Needs (2024-2033 in MW)** | | |
|---|---|---|---|---|---|---|---|---|---|
| | High | Reference | Low | High | Reference | Low | High | Reference | Low |
| Pickle Lake | 20 | 18 | 15 | 36 | 28 | 17 | 59 | 47 | 11 |
| Red Lake | 30 | 30 | 30 | 62 | 44 | 36 | 75 | 48 | 39 |
| Ring of Fire | 22 | 22 | 4 | 67 | 27 | 5 | 73 | 29 | 7 |

Given the magnitude of the increase in electrical demand associated with expanding an existing mine or opening a new mine, as well as growth in electricity demand from growing communities, the area is currently deficient in supply capacity and is expected to become increasingly deficient over the near, medium, and long term.

### Options Analysis

The technically feasible options available to meet needs in the Red Lake, Pickle Lake and Ring of Fire subsystems and their implementation timing are outlined in Table 2 below. All costs are net present cost in 2014 dollars, unless stated otherwise (a detailed description of costing methodology can be found in Appendices 10.6, 10.7, and 10.8):

[2] Existing system is thermally limited.

**Table 2: Summary of Options**

| Implementation Timing | Pickle Lake Subsystem | Red Lake Subsystem | Ring of Fire Subsystem |
|---|---|---|---|
| **Conservation and DG Options** | | | |
| Near term and medium to long term (2014-2033) | Customers may investigate opportunities for additional conservation beyond targets and DG resources to suit their own electrical requirements; Industrial Accelerator Program ("IAP"), Aboriginal Conservation Program, Aboriginal Community Energy Plans Program, remote renewable opportunities after grid expanded to supply remote First Nation communities. | | |
| **Transmission Options** | | | |
| Near term (2014-2018) | Build a new 115 kV<br>OR<br>230 kV transmission line from the Dryden/Ignace area to Pickle Lake<br>**Cost: $80 M - $114 M** | Upgrade existing transmission lines serving Red Lake (E4D and E2R)<br>**Cost: $11 M** | East-West Corridor Option:<br>Build a new 115 kV transmission line from Pickle Lake to Ring of Fire for demand up to 67 MW, or build a new 230 kV line if greater than 67 MW.<br>**Cost: $106 M - $156 M**<br>OR<br>North-South Corridor Option:<br>Build a new 230 kV transmission line from either Marathon or a point east of Nipigon to Ring of Fire<br>**Cost: $175 M** |
| Medium to long term (2019-2033) | | If load in the Red Lake subsystem exceeds 109 MW:<br>Install additional voltage support<br>**Cost: $1 M**<br>If load in the Red Lake subsystem exceeds 130 MW:<br>Build a new 115 kV or 230 kV transmission line between Dryden and Ear Falls<br>**Capital Cost: $91 M - $132 M**[3] | |
| **Generation Options** | | | |
| Near term (2014-2018) | Gas-fired generator at Pickle Lake fuelled by compressed natural gas, sized and expanded to meet demand growth of up to 31 MW in medium term and up to 76 MW in long | Gas fired generator utilizing up to 30 MW of available gas pipeline capacity at Red Lake<br>**Cost: $51 M** | On-site generation fuelled by compressed natural gas or diesel,<br>**Cost: $209 M - $946 M**[4]<br>Separately connect remote communities |
| Medium to long term (2019-2033) | | Gas-fired generator utilizing up to 30 MW of available gas pipeline | |

[3] For comparison with other options, the long-term Red Lake options are presented as capital costs. The NPV of transmission in the long term is $10-15 M. This number is low as the majority of costs are not incurred in the 20 year planning period of this IRRP and the NPV is expressed in 2014 dollars (multiple years of discounting). A fuller description of costing methodology can be found in Appendices 10.6, 10.7, and10.8.

[4] Range indicates variation in cost of diesel and compressed natural gas as well as sizing of the generation facility to accommodate the low, reference or high forecast scenarios.

| | | | |
|---|---|---|---|
| | term<br>**Cost: $158 M - $317 M** | capacity at Red Lake, followed by additional 30 MW at Ear Falls if a new gas pipeline is built<br>**Capital Cost: $95 M - $ 153 M**[5] | **Cost: $ 62 M**<br>**Total Cost: $ 272 M - $1,009 M** |
| | | | |

This regional plan considers overall societal costs[6] in determining the least-cost options for supplying the study area. The analysis in this regional plan does not consider the allocation of costs that are attributable to individual customers in the area or how this may affect individual customer decisions on pursuing the societal least-cost options. The final determination of cost allocation between parties will be made through the applicable regulatory process and/or through commercial agreements. For example, cost allocation of transmission and distribution infrastructure is made by the Ontario Energy Board ("OEB"), benefitting customers, and/or transmitters and distributors in the area in accordance with rules set out in the Transmission System Code ("TSC") and Distribution System Code ("DSC").

**Summary of Aboriginal, Stakeholder, and Public Feedback**

*Aboriginal Consultation*

The Ministry of Energy delegated the procedural aspects of consultation to the OPA and identified 44 First Nation communities and four Métis communities to be consulted on

[5] For comparison with other options, the long-term Red Lake options are presented as capital costs. The NPV of generation in the long term is $6-8 M. This number is low as the majority of costs are not incurred in the 20 year planning period of this IRRP and the NPV is expressed in 2014 dollars (multiple years of discounting). A fuller description of costing methodology can be found in Appendices 10.6, 10.7, and10.8.

[6] Societal costs include direct electricity project costs associated with real incremental goods and services (capital cost of engineering, equipment, operations and maintenance, fuel, etc.) but excludes the cost of land, taxes and potential impact benefit agreements that may be reached with affected First Nations, which proponents may be required to pay. Governments (and their agencies) undertake projects of infrastructural, environmental or health and safety enhancements in the wider public interest, assessing project merits in terms of the long-term return to current and future generations of society as a whole, using a social discount rate ("SDR"). The OPA uses a four-percent SDR to determine the present value of options over the planning period.

the Draft North of Dryden IRRP. The OPA and Ministry of Energy provided written notice to each community. The OPA also followed up by telephone to each community and sent all presentation material to each community in advance of the sessions.

The OPA held consultation sessions for the First Nation communities in Thunder Bay on June 18, 2014, June 25, 2014, and October 16, 2014, and in Dryden on June 26, 2014. The OPA met with Red Sky Métis Independent Nation on June 19, 2014 at Red Sky's office in Thunder Bay.

The OPA was in contact with the Métis Nation of Ontario ("MNO") on a number of occasions via telephone and email to set up appropriate times for regional consultation meetings with MNO's member communities. The OPA endeavoured to meet with the MNO and its chartered communities and remains open to such meetings.

To date there have not been any specific concerns expressed regarding potential impacts of the regional plan on any Aboriginal or treaty rights.

*Municipal Engagement*

The OPA met with municipal representatives in person to solicit feedback on the Draft North of Dryden IRRP to be incorporated into the North of Dryden IRRP. The OPA met with municipal representatives from Pickle Lake, Greenstone, Red Lake, Sioux Lookout, Marathon, Dryden and Ignace in December 2013 and February 2014.

Following the municipal engagement meetings, several common themes emerged from the various municipalities and mainly centered on option preference, cost responsibility, and urgency for development.

*Written Feedback*

Since the posting of the Draft North of Dryden IRRP, the OPA has received written feedback and has followed up with those who contributed written submissions. Written feedback was submitted from the Common Voice Northwest Energy Task Force

("CVNW"), the township of Pickle Lake, Imperium Energy on behalf of the municipality of Greenstone, the Ontario Waterpower Association, Ontario Power Generation ("OPG"), Gold Canyon Resources Inc., Energy Acuity, and an independently represented stakeholder.

In general, written submissions asked clarifying questions regarding the content in the draft report. It should be noted that CVNW submitted a 51-page report of comment covering topics across the entire Northwest. The OPA has considered the input in this report, has met with CVNW since publishing the draft report, and will continue to consider their feedback for regional planning initiatives across northwestern Ontario.

Based on written feedback provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, OPG identified that Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls Switching Station ("SS") associated with the installation of voltage control devices. The OPA has considered this feedback in finalizing the plan.

*Webinar*

The first draft of the North of Dryden IRRP was posted to the OPA's website in August 2013 and a webinar was held on November 21, 2013 to present the draft IRRP and solicit feedback. Main points of feedback were consistent with that received in written submissions and engagement and consultation meetings.

**Recommended Solutions/Actions to be initiated in the near term**

The OPA recommends the following solutions for implementation as soon as possible:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem), installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control

devices at Pickle Lake, and transferring the existing load on the line between Ear Falls and Pickle Lake (E1C) to be supplied by this new line;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. Having the Independent Electricity System Operator ("IESO")/OPA initiate discussions with OPG for new reactive power services provided by Manitou Falls Generating Station ("GS") if it is confirmed to be beneficial to the ratepayer.

These recommendations are the most cost-effective options that can be implemented in a timely manner and provide flexibility for meeting a broad range of long-term forecast scenarios.

The estimated combined present value cost of recommendations (1) and (2) during the planning period is about $124 million[7]. Recommendation (3) may reduce the estimated cost further. Together these projects increase the LMC of the Pickle Lake subsystem from 24 MW to 160 MW, and increase the LMC of the Red Lake subsystem from 61 MW to 130 MW.

The OPA understands that near-term actions for implementing a new line to Pickle Lake have been initiated by two proponents. Additionally, the OPA understands that Hydro One and various customers in the Red Lake area have initiated discussions to implement the upgrades from Dryden to Red Lake. Implementation of the new 230 kV line to Pickle Lake and the 115 kV line upgrades from Dryden to Red Lake continue to be supported by the OPA.

[7] The August 2013 draft identified this cost as $234-271 million. This change in cost is due to a change in methodology for the NPV economic analysis – treating avoided system generation as a benefit of generation options, rather than a cost to transmission options (as in the 2013 draft). NPV economic analysis is an analysis tool to compare costs over a time horizon, and is not the same as the total project cost for the option being investigated.

**Options for the medium to long term period**

*Pickle Lake Subsystem*

The recommendation to build a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake in the near term would be sufficient under all forecast scenarios for the medium to long term.

*Red Lake Subsystem*

Following the completion of the near-term recommendations, the 130 MW LMC is expected to be sufficient beyond the planning period for the low and reference forecast scenarios, and until 2030 for the high scenario as shown in Table 1. Therefore, the near-term recommendations are expected to be sufficient to meet the needs of the Red Lake subsystem for the long term.

As shown in Table 2, two options have been investigated for the Red Lake subsystem to address any forecasted load in excess of 130 MW. The OPA recommends that these options, incremental natural gas-fired generation at Red Lake and a new transmission line, be retained as viable long term options and re-evaluated in the next planning cycle (1-5 years) for this IRRP. Re-evaluating plans up to every 5 years is consistent with OEB requirements in the TSC, DSC and the OPA license.

*Ring of Fire Subsystem*

There are several options for supplying the Ring of Fire subsystem depending on the load growth scenario. The analysis indicates that the Ring of Fire subsystem can be cost-effectively served by a 115 kV transmission connection from Pickle Lake (serving five remote communities and mines at the Ring of Fire), if demand over the long term is 67 MW or less. If demand is reasonably certain to exceed 67 MW in the subsystem, a 230 kV transmission line utilizing an East-West corridor from Pickle Lake, or a 230 kV transmission line utilizing a North-South corridor from either Marathon or east of Lake Nipigon would be required, where these alternatives have approximately equal cost.

The 230 kV transmission options are also expected to be more cost-effective from a societal perspective than the combined cost of developing local generation to serve the total mining load and separately connecting remote communities to Pickle Lake.

The OPA is aware of ongoing work for infrastructure development for the Ring of Fire. Common infrastructure corridors serving multiple uses provide synergies for cost and environmental approvals, and may reduce environmental impacts. The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

**Conservation Options**

Recently, the OPA has received new direction[8] from the Minister of Energy pertaining to the framework for conservation programs moving forward. Directives from the Minister of Energy set conservation targets, which Local Distribution Companies ("LDC") will plan to meet through the development of conservation plans and programs for their service area. The spirit of this new direction is to provide more opportunity for LDCs, communities, and industry to participate in conservation initiatives so a broader scope of programs is expected to be tailored to the local needs of the region. For remote communities, conservation opportunities are considered in the Remote Community Connection Plan.

Furthermore, the following programs are available through the OPA to Aboriginal Communities:

- Aboriginal Conservation Program, with the aim to provide customized conservation services designed to help First Nation communities, including remote and northern communities, reduce their electricity use in residential housing, and in commercial and institutional buildings, like stores, schools and

[8] *2015-2020 Conservation First Framework (March 31, 2014), Continuance of the OPA's Demand Response Program under IESO management (March 31, 2014), and Industrial Accelerator Program (July 25, 2014).*

band offices. This program will be offered for one additional year (ending December 31, 2015) until such time as LDCs are able to develop a CDM program which recognizes the specific requirements of on-reserve First Nation communities as per the 2015-2020 Conservation First Framework Directive.

- Aboriginal Community Energy Plans program to support Aboriginal participation in Ontario's energy sector by providing up to $90,000 per community in funding to First Nation or Métis communities for local energy planning activities, with remote communities being eligible for an additional $5,000.

Electricity demand of the industrial sector is quite significant in this area. The Industrial Accelerator Program ("IAP") is available to industrial customers as a means of achieving conservation savings with financial assistance from the OPA.

Given the large component of industrial demand and number of First Nation and Métis communities in the area, the above mentioned programs should be pursued.

**Generation Options for the Medium- to Long-term Period**

On May 30, 2014, the OPA closed submissions for the Northwest Ontario Request for Information ("NW RFI"). The purpose of the NW RFI was to gather information on the potential availability of diverse resource options in northwestern Ontario, with particular focus on the interim period to 2020. As part of the NW RFI, the OPA received submissions totaling over 4000 MW for the entire Northwest region. Of the over 4000 MW, a few potential projects were identified in the North of Dryden sub-region and were consistent with the generation options investigated as part of this IRRP.

Procurement of generation is not recommended to be pursued at this time for meeting needs in the North of Dryden sub-region. However, if a generation solution is required for other areas of the Northwest, local benefits of these options to the North of Dryden sub-region will be re-evaluated.

# 2 INTRODUCTION

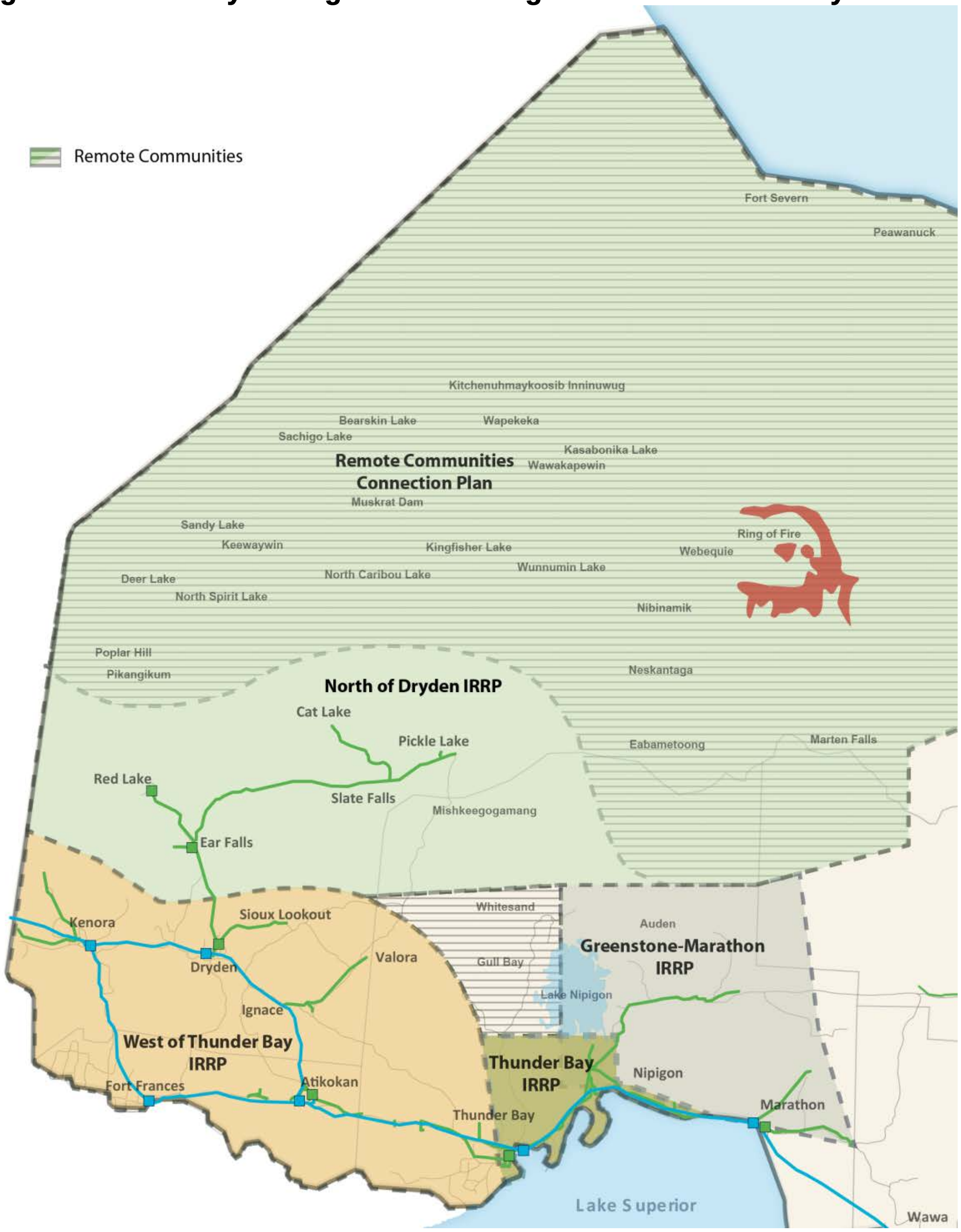
## 2.1 The North of Dryden Sub-Region

The North of Dryden Integrated Regional Resource Plan (“IRRP”) is one of several electricity planning initiatives that the Ontario Power Authority (“OPA”) is undertaking for the Northwest Ontario region. Figure 4 identifies the IRRP initiatives currently being undertaken by the OPA in the Northwest Ontario region. The North of Dryden IRRP accounts for the demand requirements in the North of Dryden sub-region.

The Thunder Bay IRRP, West of Thunder Bay IRRP and Greenstone-Marathon IRRP were initiated fall 2014. A Scoping Outcome Assessment Outcome Report for northwestern Ontario, which includes the Terms of Reference for three new IRRPs, is available on the OPA’s website, consistent with Ontario Energy Board (“OEB”) requirements. The Terms of Reference for the West of Thunder Bay IRRP and the Greenstone-Marathon IRRP include considerations for relationships with the North of Dryden IRRP.

The North of Dryden sub-region is a natural resource rich area in northwestern Ontario, with existing mining, forestry, and hydroelectric generation operations, as well as potential for substantial new resource development. Mining sector expansion, including expansion of existing mines as well as the development of new mines, is a major driver for electricity demand growth in the area, both at mine sites and through growth in industries that support the mining sector. Another major driver for electricity demand growth in the area is the economic connection of remote First Nations communities (“remote communities”) to the provincial transmission grid, which are currently served by isolated diesel generation systems.

**Figure 4: Summary of Regional Planning Initiatives Underway in Northwest Ontario**




The transmission system supplying the North of Dryden sub-region is currently at capacity. This IRRP recommends options to provide new high voltage electrical capacity to meet near-term growth, while providing options to meet future growth as it becomes more certain. These near-term recommendations are presented as action items for immediate or early deployment. Options to address potential longer-term needs are also

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identified, but the OPA does not make a recommendation on a preferred option at this time, as the longer term still remains uncertain and adequate time is available to continue to monitor the situation closely. The OPA will continue to monitor demand growth and reevaluate longer-term options in future planning cycles for the North of Dryden sub-region. When a decision for the longer-term is required, the OPA will make a recommendation for solutions to be implemented.

The North of Dryden sub-region (shown in more detail in Figure 5) is contained within First Nation Treaty areas 3, 5, 9 and the Robinson-Superior Treaty area. It also includes portions of Region 1 and Region 2 of the Métis Nation of Ontario ("MNO"). The southern portion of the area (as shown in Figure 5) is currently served by Ontario's transmission grid and is bounded by Dryden to the southwest, Red Lake to the northwest, and Pickle Lake to the northeast. Current mining activity is mostly contained in this portion of the area, and broadly focused around the Towns of Ear Falls, Red Lake and Pickle Lake.

The northern portion of the North of Dryden sub-region (as shown in Figure 5) is comprised of 21 remote communities, one operating mine and the mine development area in the Hudson Bay lowlands known as the Ring of Fire. At present, the mine north of Pickle Lake is connected to the transmission grid by a privately owned transmission line. There are 25 remote First Nations communities that are distant from the existing provincial transmission system and are currently supplied electricity by local diesel generation facilities. On August 21, 2014, an updated draft Remote Community Connection Plan was made available on the OPA website.[9] The Remote Community Connection Plan demonstrates a business case to connect 21 of 25 remote communities that currently rely on diesel generation, to the provincial transmission grid. The business case is based on the avoided cost of diesel fuel. For the purpose of this regional plan, 21 of the 25 communities are assumed to connect to Ontario's transmission system as per the OPA's Remote Community Connection Plan. Communities are expected to begin connecting in the early 2020s.

[9] http://www.powerauthority.on.ca/sites/default/files/planning/OPA-technical-report-2014-08-21.pdf

**Figure 5: Map of Northwest Ontario Showing the Existing Transmission System**


Distribution connected customers in the North of Dryden sub-region are served by Hydro One's distribution system. There are also a number of large industrial customers that are connected directly to the transmission system in the area and served by Hydro One's transmission system.

## 2.2 Purpose and Scope of the IRRP

This regional plan assesses the near-term and medium- to long-term electricity supply needs of the North of Dryden sub-region and identifies the options which are available to address these needs in a cost-effective, reliable, and timely manner. The regional plan is intended to identify alternatives and recommended options to local customers, proponents, and local government so development work may proceed. Proponents may also choose to use this regional plan to support the regulatory proceedings they will undertake to seek approval for their projects.

Regional planning for the North of Dryden sub-region began before the OEB's formalized regional planning process was developed as part of the Renewed Regulatory Framework for Electricity ("RRFE"). Consequentially the North of Dryden IRRP does not have a corresponding Scoping Assessment Outcome Report. The North of Dryden IRRP is considered a "transition plan" as per the Planning Process Working Group ("PPWG") report on Regional Planning to the OEB. This version of the North of Dryden IRRP has transitioned and aligned with OEB requirements for the IRRPs as per the OPA's license.

In 2010, the OPA, Hydro One and the Independent Electricity System Operator ("IESO") began working together to assess the ability of the electricity system in the North of Dryden sub-region to meet forecast growth over the near, medium and long term, and to develop integrated plans to address needs that have been identified. Since beginning this planning work, the OPA has engaged existing and potential customers in the area to identify the size and scope of their future electricity needs in the North of Dryden sub-region. The IESO has also completed a number of System Impact Assessments ("SIAs") and feasibility studies for customers requesting additional capacity.

In addition to the regional planning requirements outlined by the OEB, the Minister of Energy identified in the 2010 Long-Term Energy Plan ("LTEP") that the OPA would develop plans to enable the connection of remote First Nations communities, and identified the development of a new transmission line to Pickle Lake to be a priority transmission project, with the scope and timing to be determined by OPA. In February 2011, the OPA received an updated Supply Mix Directive ("SMD") from the Minister of Energy. The updated SMD requires that the OPA develop a plan to connect remote First Nation communities north of Pickle Lake. In December 2013, the Ministry of

Energy released the second LTEP which reiterated that connecting remote First Nation communities in northwestern Ontario is a priority.

Since 2009, the OPA has been working with remote First Nations communities through the Northwestern Ontario First Nation Transmission Planning Committee ("NWOFNTPC") to identify communities that are economic to connect to the provincial transmission system. Through this partnership, planning is underway for connecting most of these communities to the grid and for developing local solutions for the remaining communities to cost-effectively reduce their reliance on diesel fueled generation.

The North of Dryden IRRP is affected by connection of remote communities in two primary ways:

1. The transmission facilities serving the area must be capable of supplying the electrical demand resulting from the connection of these remote communities; and

2. Options for coordinating connection with mining developments, especially in the Ring of Fire area, must be investigated in accordance with assumptions in the Remote Community Connection Plan.

As new information on the connection of the remote communities becomes available, the North of Dryden IRRP will be updated accordingly and consistent with the regional planning process and PPWG report.

It should also be noted that regional plans consider overall societal costs[10] in determining the least cost options for supplying a study area. This analysis does not

[10]Societal costs include direct electricity project costs associated with real incremental goods and services (capital cost of engineering, equipment etc, operating and maintenance, fuel etc.), but excludes the cost of land, taxes, and potential Impact Benefit Agreements that may be reached with affected First Nations, which proponents may be required to pay. cont'd...

consider how the allocation of costs attributable to individual customers in the area may affect their decision to pursue the societal least cost options. The final determination of cost allocation between parties will be determined by the appropriate regulatory process or commercial agreement. For example, cost allocation of transmission and distribution infrastructure is made by the OEB, benefitting customers, and/or transmitters and distributors in the area in accordance with the rules set out in the Transmission System Code ("TSC") and Distribution System Code ("DSC").

Other planning activities for the region will consider supply needs to the Dryden area for supply of expected load growth in the North of Dryden sub-region. Some of the planning and development work that is underway to ensure an adequate supply is available in the overall Northwest region includes development work being undertaken by NextBridge Infrastructure for an expanded East-West Tie ("EWT"), the May 30, 2014 Northwest Request for Information ("NW-RFI"), and the regional planning initiatives summarized in Figure 4.

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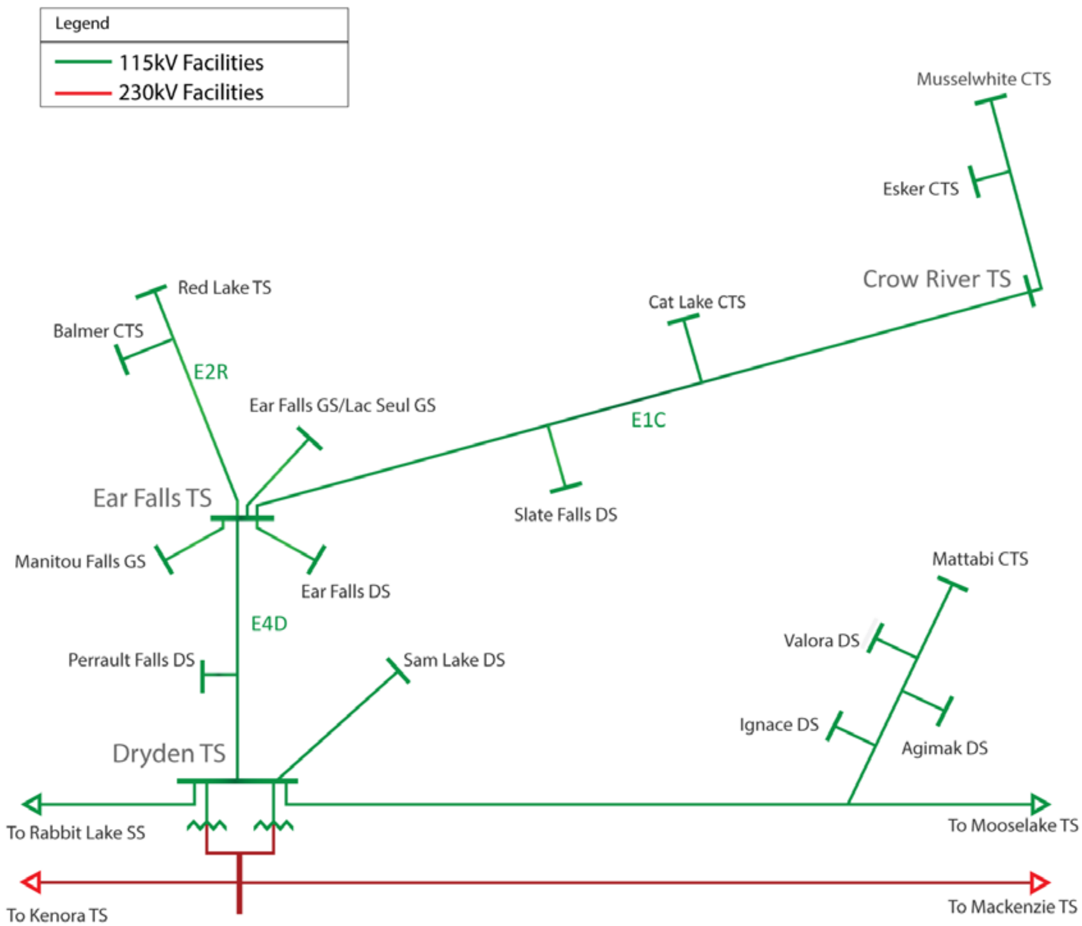
...Governments (and their agencies) undertake (or mandate) projects of infrastructural, environmental, or health and safety enhancement in the wider public interest, assessing project merit in terms of the long-term return to current and future generations of society as a whole, using a Real Social Discount Rate (Real "SDR"). The OPA uses a 4% Real Social Discount Rate for determining the present value of options over the planning period.

# 3 NORTH OF DRYDEN TRANSMISSION AND GENERATION FACILITIES

Currently, electricity customers in the North of Dryden sub-region are supplied by a single-circuit 115 kV radial transmission line (“E4D”) emanating from Dryden TS and by local hydroelectric generation. Dryden TS is a major supply station for this area, where the voltage is stepped down from the regional 230 kV system to 115 kV to serve local community and industrial customers as shown in Figure 6 below.

**Figure 6 Existing North of Dryden Transmission System**

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At Ear Falls TS, the 115 kV supply branches to the north, east, and west to supply customers and incorporate generation in the area. Hydroelectric generation is connected to the transmission system at Ear Falls generating station (“GS”) (17 MW Ear Falls + 12.1 MW Lac Seul) and at Manitou Falls GS (73.1 MW). To the north of Ear Falls, the E2R transmission line (“E2R”) supplies Red Lake area mining and community customers. East of Ear Falls, the E1C transmission line (“E1C”) supplies the Town of Pickle Lake, Cat Lake First Nation, Slate Falls First Nation, Mishkeegogamang First Nation, as well as a mine via a privately-owned 115 kV transmission line (“M1M”).

For the purposes of this regional plan, the North of Dryden sub-region is divided into three main subsystems, as shown in Figure 7, the Pickle Lake subsystem, the Red Lake subsystem, and the Ring of Fire subsystem. At present, the Ring of Fire subsystem has no transmission infrastructure and is not connected to the provincial transmission grid, and the Pickle Lake subsystem is supplied downstream of the Red Lake subsystem from Ear Falls via E1C.

The Pickle Lake subsystem includes all demand planned to be served by E1C at Cat Lake CTS, Slate Falls DS, Crow River DS, as well as a mine north of Pickle Lake and any new customers that may connect in the Pickle Lake area in the future. The Pickle Lake subsystem also includes 10 remote communities north of Pickle Lake that are identified to connect to Pickle Lake in the 2014 Remote Community Connection Plan.

The Red Lake subsystem includes all load and generation connected and planned to be served by E4D and E2R, at Perrault Falls DS, Ear Falls TS, Red Lake TS, Balmer CTS, and the six remote communities north of Red Lake that are identified as being economic to connect to Red Lake TS in the 2014 Remote Community Connection Plan. As mentioned previously, there is 102.2 MW of hydroelectric generation at Ear Falls GS and Manitou Falls GS.

**Figure 7: North of Dryden Subsystems**


The Ring of Fire subsystem does not include any existing transmission facilities. The subsystem includes five remote communities that are identified for connection in the 2014 Remote Community Connection Plan as well as potential future industrial customers at the Ring of Fire mine development area.

Due to the current system configuration, when a transmission line in the North of Dryden sub-region is forced out of service all load connected to it is lost. In the event that E4D is removed from service, some of the North of Dryden system can be restored

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by islanded[11] hydroelectric generation in the Ear Falls area until E4D is returned to service. While the area is islanded from the system and supplied by local generation, the amount of load that can supplied is limited to the available generation output.

Historically, the reliability of electricity supply to some customers in the North of Dryden sub-region has been worse than the average for other customers in northwestern Ontario. Specifically, customers in the Pickle Lake subsystem (currently supplied by E1C) have experienced, on average, 14 unplanned outages per year over the past 10 years.[12] This compares to an average of about three unplanned outages per year for customers served by the other 115 kV lines in northwestern Ontario.[13] Planning for the north of Dryden system includes consideration of this historical performance.

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[11] Islanded: when one part of the system is disconnected and operated separately from the rest of the Ontario electricity system.
[12] Hydro One Networks Inc. through correspondence.
[13] Hydro One Networks Inc. through correspondence.

# 4 HISTORICAL ELECTRICITY DEMAND

## 4.1 Historical Electricity Demand

Demand for electricity in the North of Dryden sub-region is driven by a number of factors including mining and forestry activity, as well as local community growth. Mining sector expansion is the primary driver of growth in electricity demand in the area. The north of Dryden area is currently winter-peaking. As shown in Figure 8, peak demand in the North of Dryden sub-region has been growing by approximately 1.9% since 2004. Historical demand includes only the Pickle Lake and Red Lake subsystems, since the Ring of Fire subsystem has not yet developed beyond the five remote communities located east of Pickle Lake. Historical demand figures also do not include remote community demand, since they are not currently connected to the provincial transmission system.

**Figure 8: North of Dryden Historical Transmission Connected Demand**

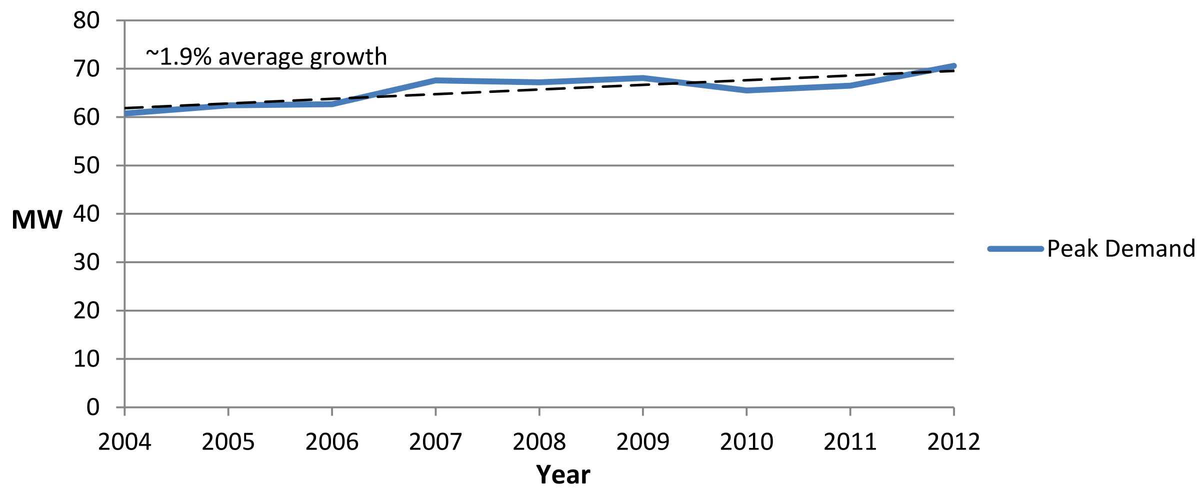
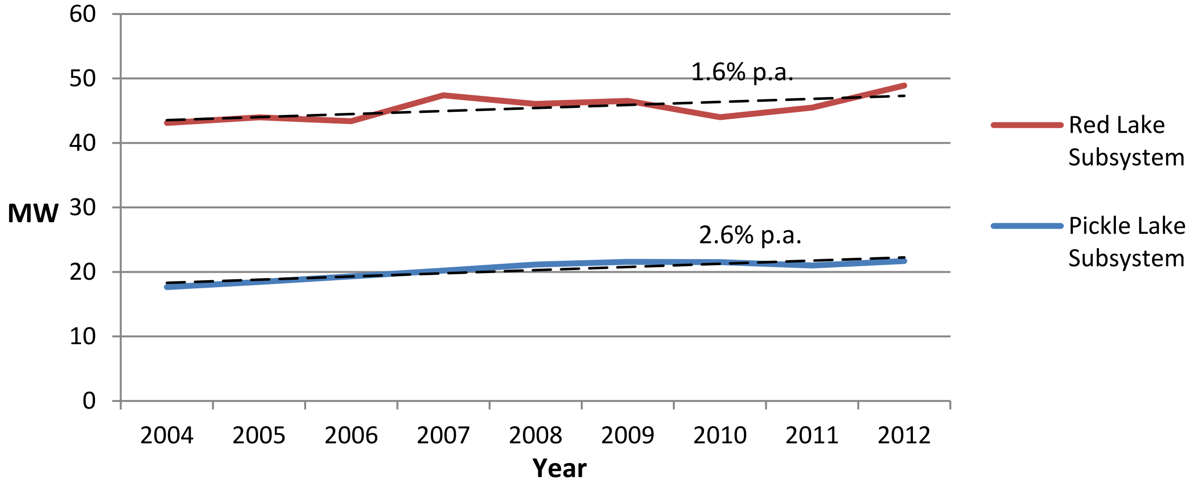



Figure 9 shows that growth in electricity demand has also varied between the Red Lake and Pickle Lake subsystems, with annual growth in electricity demand averaging 1.6% in the Red Lake subsystem and 2.6% in the Pickle Lake subsystem between 2004 and 2012.

**Figure 9: North of Dryden Historical Demand by Subsystem**




In 2012, 61 MW of capacity was allocated to customers in the Red Lake subsystem, while 24 MW of capacity was allocated to customers supplied in the Pickle Lake subsystem. When the load of the remote communities in each subsystem are added to the connected load, the total load in 2012 increases to 67 MW in the Red Lake subsystem and 31 MW in the Pickle Lake subsystem. At present, no customers in the Ring of Fire subsystem are connected to the provincial grid; however, the combined demand of the five remote communities in the subsystem was about 3 MW in 2012.

## 4.2 Existing Distributed Generation Resources

Distributed generation is small-scale generation sited close to load centers; it helps supply local energy needs while at the same time contributing to meeting provincial demand. Along with other OPA procurement processes, the introduction of the *Green Energy and Green Economy Act, 2009* and the associated development of the Feed-in Tariff ("FIT") program have encouraged the development of distributed generation resources in Ontario. These procurements take into consideration the system need for generation as well as cost.

Presently, there are five contracted microFIT projects, and one contracted FIT project in the North of Dryden sub-region. All of these projects are located in the Red Lake subsystem. Of these projects, four microFIT solar projects are located in Red Lake with a total contract capacity of 39.3 kW and one microFIT solar project is in Ear Falls with a contract capacity of 10 kW. Analysis of the ability of solar resources in the North of Dryden sub-region to contribute to meeting local demand during the fall months has been estimated to be 5% of contract capacity. Therefore, these units are expected to contribute 2.5 kW to the LMC of the Red Lake subsystem. The FIT project is the Trout Lake River FIT small hydro project, a run of river hydroelectric project near Ear Falls, with a contract capacity of 3.75 MW[14]. The dependable generation level for this project (see Appendix 10.3.2) and its contribution to the LMC of the Red Lake subsystem is assumed to be 0 MW.[15] In total, the contribution of these DG units to the LMC of the Red Lake subsystem is expected to be 2.5 kW (0.0025 MW).

Currently, there are a number of diesel generators that provide backup/emergency supply at mine sites, which are required for health and safety purposes. Generally, these units are not configured for grid connection and thus are not currently available to supply the system. Even if they were configured to connect to the grid, there may be other limitations on their ability to reliably supply load customers on a regular basis including: their age, efficiency, level of emissions, prescribed limits in their operating approvals and their operating and maintenance costs. These units may have some potential to operate as short-term demand management resources, but given the available information they cannot be relied upon to provide the capacity and energy required to meet the needs of the North of Dryden sub-region. Therefore, they have not been considered further in this regional plan.

The Request for Information for Electricity Resources in Northwestern Ontario ("NW-RFI") was issued to better understand the availability of all potential resources in northwest Ontario including the North of Dryden sub-region, with particular focus on the

[14] Trout Lake River GS, is a contracted FIT small hydro project currently under development, with an expected commercial operation date of Q1 2015.
[15] The performance of the facility during drought conditions has not yet been determined, however, the anticipated contribution based on similar facilities in the area, is much less than the tolerance of the modelling software used for this study.

interim period to 2020. The OPA has received submissions to the NW-RFI. Generation options in this plan have considered the relevant NW-RFI submissions. Should new information become available it will be included at the next update of this regional plan.

# 5 FORECAST ELECTRICITY DEMAND

To develop the demand forecast the OPA worked with Hydro One (the transmitter and local distribution company serving the North of Dryden sub-region), existing and potential transmission connected industrial customers around Ear Falls, Red Lake, and Pickle Lake[16] and the Ring of Fire, municipalities, business associations, as well as remote First Nations communities in northwest Ontario.

## 5.1 New Demand from Connection of Remote First Nation Communities

The findings of the Remote Community Connection Plan indicate that due to the high and growing cost of diesel fuel as well as the high cost of operating and maintaining remote diesel generation systems, transmission connection of up to 21 remote communities can avoid substantial future costs of about $1 billion over 40 years and therefore economically justifies the connection of the corresponding 21 remote communities to the provincial transmission grid. For the purposes of this IRRP, it has been assumed that these communities will pursue a connection and therefore includes the demand of the corresponding remote communities in the North of Dryden IRRP forecast. The Remote Community Connection Plan indicates that communities may begin connecting between 2018 and 2020, following the development of required capacity in the North of Dryden sub-region transmission system.

## 5.2 Residential and Commercial Forecasted Demand

The OPA worked with Hydro One to establish the Residential and Commercial component of the demand forecast in the North of Dryden sub-region. The OPA then removed the industrial component of the load that is connected to the distribution system to determine the forecasted residential and commercial forecasted demand. Hydro One Distribution supplies electricity to customers at the following transformer

[16] The load growth is based on information provided to the OPA by Hydro One Networks Inc. and industrial customers in the North of Dryden sub-region. Hydro One provided information relating to existing distribution facilities North of Dryden; this includes existing community loads and some industrial loads. The OPA worked with existing and potential industrial customers to determine their expected near and long-term electricity needs. The forecast has been shared with Common Voice Northwest's Energy Task Force among other interested stakeholders.

stations: Perrault Falls DS, Ear Falls DS, Red Lake TS, Crow River DS, and Slate Falls DS. Cat Lake CTS is owned by Cat Lake Power Utility Ltd., and is supplied by Hydro One's transmission system from circuit E1C.

## 5.3 New and Expanding Mining Projects

The majority of forecasted demand growth in the North of Dryden sub-region is anticipated to be primarily driven by the mining sector.

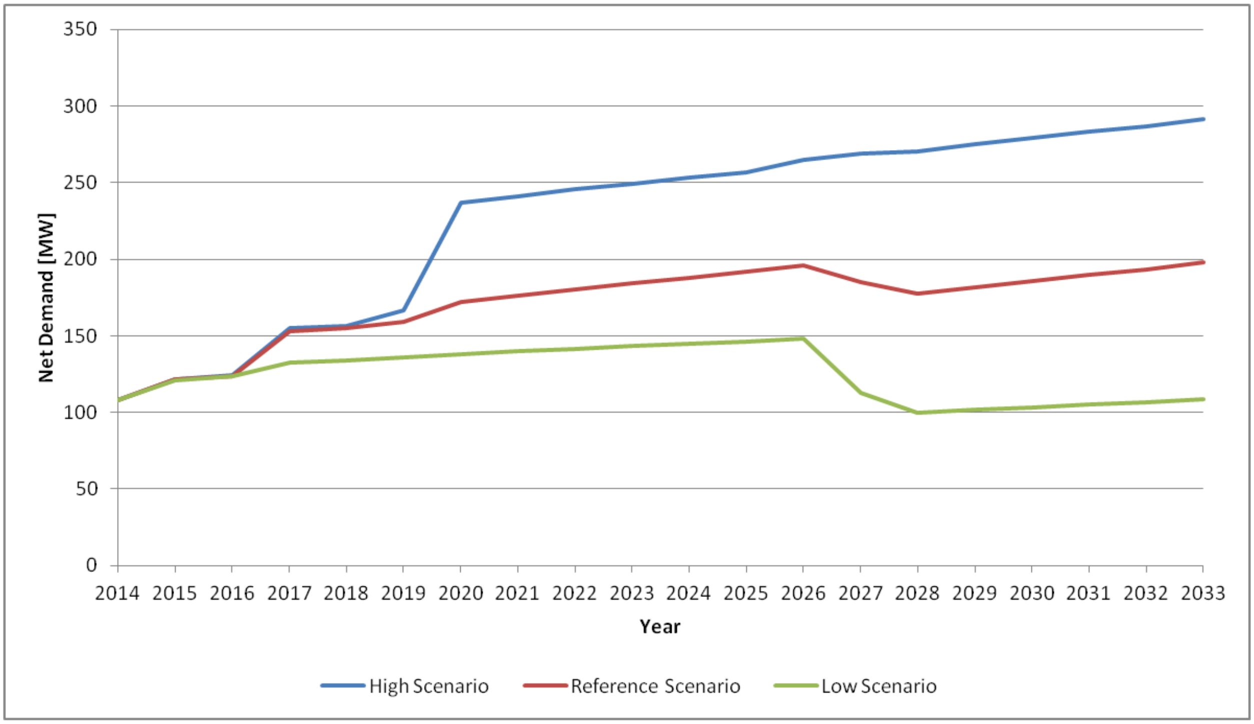
Numerous projects have been proposed in the region, representing a variety of mineral resources, stages of feasibility and development and potential environmental impacts. As mining is a commodity-based industry, there is uncertainty with the timing of mining projects, especially those that are in the relatively early stages of development. This corresponds to uncertainty in the forecasted electrical demand for the area. Recognizing the risk associated with uncertainty in the forecasted demand, the OPA produced three load scenarios. The OPA produced high and low forecast scenarios to capture the range of variability in future electrical demand and a reference forecast to reflect a likely scenario of future demand based on the information presently available.

Through engagement with the mining companies, mining associations and other stakeholders in the region, and by reviewing available technical documents produced by the mining companies regarding their proposed projects, the OPA categorized projects according to the likelihood that they will be developed within their proposed timelines. The projects have been categorized based on several factors, including:

- Stage of development (e.g. under construction, undergoing an Environmental Assessment ("EA"), still in exploration, etc.)
- Financial feasibility (e.g. results of publically available economic assessments)
- Potential environmental impacts
- Existing infrastructure and accessibility
- Global markets (e.g. commodity prices, customers and demand)

Figure 10 shows the forecast range over the planning period.

**Figure 10: North of Dryden sub-region Net Demand Forecast**

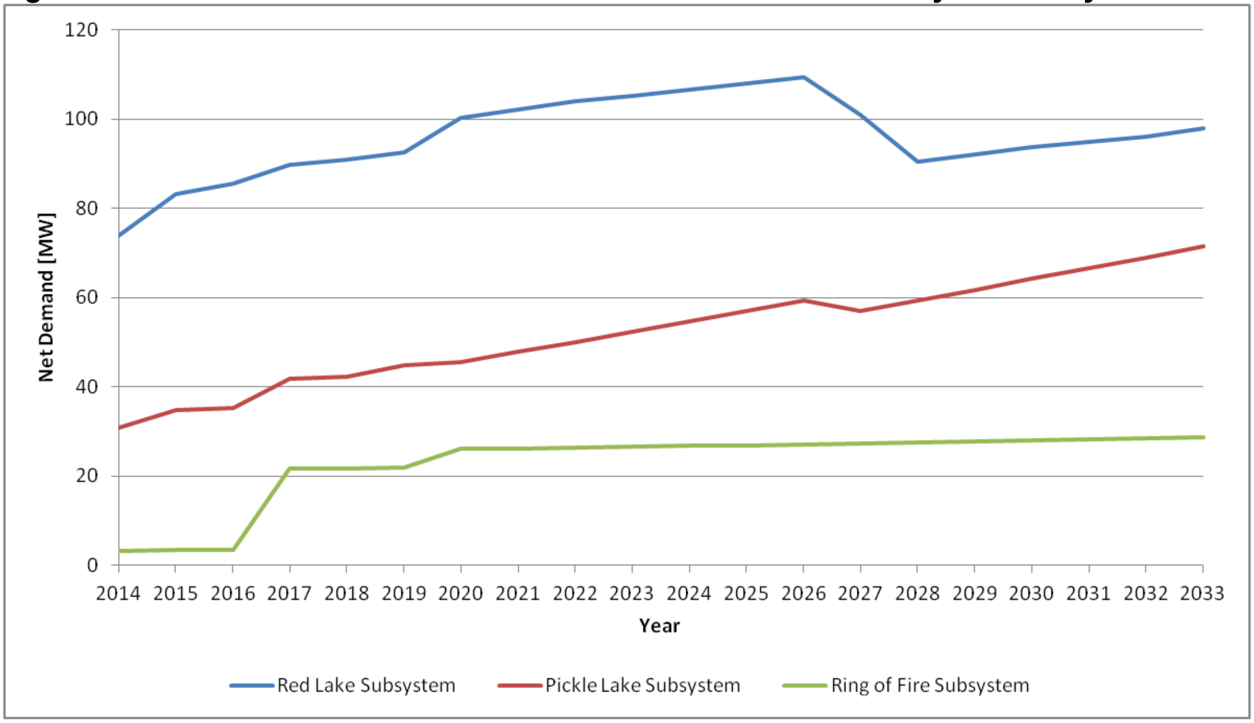



The following descriptions provide the scope of regional activity under the three scenarios.

## 5.4 Reference Scenario Demand Forecast

Under this scenario, it is assumed that projects currently under construction will be completed and commissioned on schedule. It is assumed that projects with high grade mineral deposits and positive economic assessments will be developed by the timelines specified in their project descriptions with relatively high probability. Projects with potential for extensive environmental impacts are assumed to be unlikely to proceed in the near term as well as projects which are still in the exploration phase. Furthermore, the reference scenario assumes that modest electrical demand driven by the mining sector in the Ring of Fire area is likely to appear before 2024.

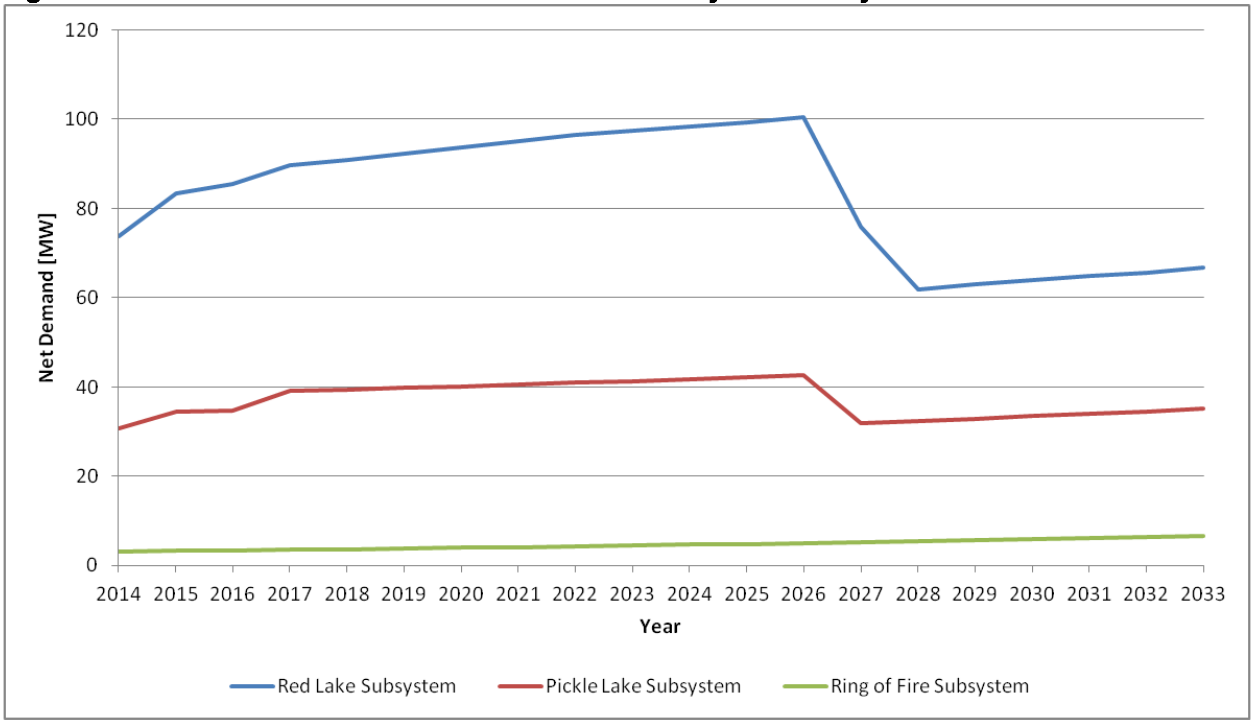
**Figure 11: Reference Scenario Demand Forecast for North of Dryden Subsystems**




## 5.5 Low Scenario Demand Forecast

This scenario assumes only the most mature and developed projects (e.g. currently under construction or applying for a leave to construct) are likely to be developed before 2024. It is assumed that other projects with a positive economic assessment will be fully developed with a 50% probability. Early stage exploration projects and projects with marginal economics or environmental, infrastructure and/or accessibility hurdles are assumed to not be developed. This scenario also assumes the Ring of Fire will not be developed before 2034.

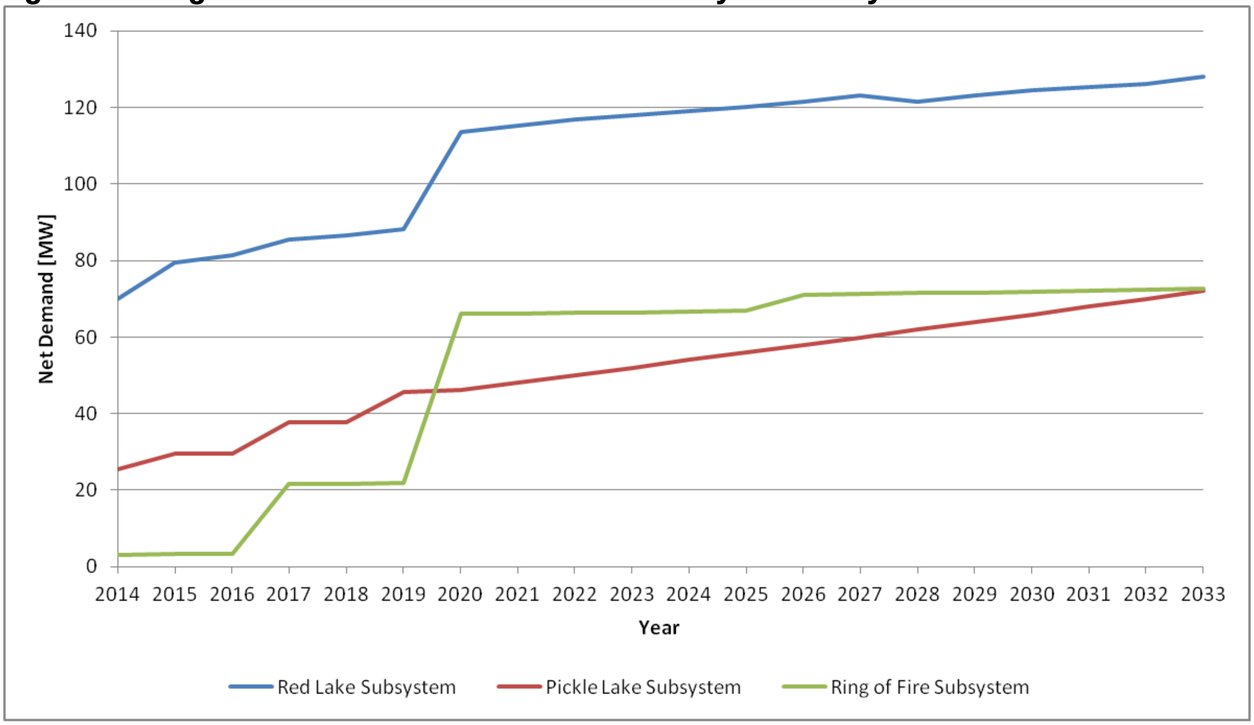
**Figure 12: Low Demand Forecast for North of Dryden Subsystems**




## 5.6 High Scenario Demand Forecast

Under the high scenario, most proposed projects are considered likely to be developed and commissioned in the near term. This scenario assumes sufficiently high commodity prices will provide financial feasibility to many projects that may otherwise be considered marginal or uneconomic. The high scenario also assumes an extensive, near- to medium-term build out of the Ring of Fire area, and that multiple mines will be operating in the region by 2020. The expansion of the mining sector is assumed to result in additional expansion of the residential sector in the region, which is also captured in this scenario.

**Figure 13: High Demand Forecast for North of Dryden Subsystems**




The OPA will continue to monitor electricity demand growth and work with existing and potential customers to maintain up to date electrical demand forecasts for the area. This information will be used to develop regular updates to the North of Dryden IRRP as per the formalized OEB Regional Planning Process.

## 5.7 North of Dryden Sub-Region Net Electricity Demand

A summary of the net demand forecast scenarios for the North of Dryden sub-region is presented in Table 3.

## Table 3: Detailed Net Demand Forecast[17]

**NET FORECAST [MW]**

| Red Lake Subsystem | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High Scenario | 74 | 83 | 85 | 90 | 91 | 93 | 118 | 120 | 122 | 123 | 125 | 126 | 127 | 129 | 128 | 130 | 131 | 133 | 134 | 136 |
| Reference Scenario | 74 | 83 | 85 | 90 | 91 | 93 | 100 | 102 | 104 | 105 | 107 | 108 | 109 | 101 | 90 | 92 | 94 | 95 | 96 | 98 |
| Low Scenario | 74 | 83 | 85 | 90 | 91 | 92 | 94 | 95 | 96 | 97 | 98 | 99 | 100 | 76 | 62 | 63 | 64 | 65 | 66 | 67 |

| Pickle Lake Subsystem | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High Scenario | 31 | 35 | 35 | 44 | 44 | 52 | 53 | 55 | 57 | 60 | 62 | 64 | 66 | 69 | 71 | 73 | 76 | 78 | 81 | 83 |
| Reference Scenario | 31 | 35 | 35 | 42 | 42 | 45 | 46 | 48 | 50 | 52 | 55 | 57 | 59 | 57 | 59 | 62 | 64 | 67 | 69 | 71 |
| Low Scenario | 31 | 34 | 35 | 39 | 39 | 40 | 40 | 41 | 41 | 41 | 42 | 42 | 43 | 32 | 32 | 33 | 33 | 34 | 35 | 35 |

| Ring of Fire Subsystem | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High Scenario | 3 | 3 | 3 | 22 | 22 | 22 | 66 | 66 | 66 | 67 | 67 | 67 | 71 | 71 | 71 | 72 | 72 | 72 | 72 | 73 |
| Reference Scenario | 3 | 3 | 3 | 22 | 22 | 22 | 26 | 26 | 26 | 27 | 27 | 27 | 27 | 27 | 27 | 28 | 28 | 28 | 28 | 29 |
| Low Scenario | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 7 |

[17] Source: OPA developed forecast as described above. Also includes forecasted values provided by Hydro One.

# 6 NEEDS IN THE NORTH OF DRYDEN SUB-REGION

Planning for the reliable supply of electricity requires anticipating potential equipment outages before they occur and designing a power system that limits the impacts to consumers, based on good utility practices as outlined in the OEB's TSC. This is accomplished through the application of planning criteria. In Ontario, the criteria for planning the transmission system are specified in the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC")[18].

In accordance with ORTAC, the transmission system shall have sufficient capability under peak demand conditions to withstand specific outages while keeping voltages, and equipment loading within applicable limits. The maximum demand that can be supplied by an electricity system in a defined area is known as the load meeting capability ("LMC") of that area. Where an area is served by a single transmission line and local generation, the LMC is determined as the capability of the transmission line during normal operation, with the dependable level of local generation respecting the loss of the largest generating unit. If the area is served by a single transmission line without local generation, the LMC is determined as the capability of the transmission line during normal operation since the loss of the single line will result in the total loss of all connected load. The following factors are considered when determining the LMC of a transmission system serving an area:

- the configuration of the system;
- the capabilities of individual elements comprising the system, for the north of Dryden system, this includes the limits of the transmission lines and the dependable levels of hydroelectric generation;[19] and

[18] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf
[19] the dependable level of the existing run of river hydroelectric generation (that is available during drought water flow conditions) is assumed to be available. Details regarding the method for determining the dependable level of hydroelectric and other renewable generation resources for the IRRP are provided in Appendix 10.3.2. Drought conditions are expected to occur about one year in every 10 years and can persist for several months at a time, when watersheds are at their lowest levels in the late summer, fall and early winter months.

- the distribution of demand in the area being supplied.

In general, the greater the distance a given electrical load is located from the inter-regional transmission system (bulk system) supply point (Dryden and/or Marathon or east of Nipigon), the lower the LMC of the system will be. This is due to losses and the need to maintain system voltages within criteria.

## 6.1 Capability of the Existing North of Dryden System to Supply Forecast Electricity Demand

At present the entire North of Dryden system is supplied from Dryden TS (via E4D) and supported by hydroelectric generation at Ear Falls. The application of ORTAC to the 115 kV transmission system serving the North of Dryden results in an LMC of 85 MW, based on the current line ratings and available dependable hydroelectric generation resources in the Ear Falls area. Existing customers have been allocated 85 MW of capacity on the system and thus the area has reached its capacity limit or LMC. Of this LMC, 24 MW is allocated to the Pickle Lake subsystem and the remaining 61 MW serves the Red Lake subsystem. Mining load in the Ring of Fire subsystem has yet to develop, and the five remote communities in the subsystem are currently supplied by isolated diesel generation. Since the Remote Community Connection Plan identifies that it is economic to connect these communities and there is currently no transmission system serving the Ring of Fire subsystem, the corresponding LMC of the existing provincial power system is 0 MW.

For new customer load to be connected and served in any of the subsystems, additional supply capacity is required. The new capacity needed in order to meet forecast demand growth as provided by Hydro One Distribution, existing and future industrial customers, and the Remote Community Connection Plan (net of planned conservation), is summarized in Table 4 below.

## Table 4: Summary of Capacity Needs to Meet the Net Demand Forecast for each Subsystem

| **Red Lake Subsystem** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LMC of Existing System | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 | 61 |
| High Scenario | 74 | 83 | 85 | 90 | 91 | 93 | 118 | 120 | 122 | 123 | 125 | 126 | 127 | 129 | 128 | 130 | 131 | 133 | 134 | 136 |
| *Need - High Scenario* | *13* | *22* | *24* | *29* | *30* | *32* | *57* | *59* | *61* | *62* | *64* | *65* | *66* | *68* | *67* | *69* | *70* | *72* | *73* | *75* |
| Reference Scenario | 74 | 83 | 85 | 90 | 91 | 93 | 100 | 102 | 104 | 105 | 107 | 108 | 109 | 101 | 90 | 92 | 94 | 95 | 96 | 98 |
| *Need - Reference Scenario* | *13* | *22* | *24* | *29* | *30* | *32* | *39* | *41* | *43* | *44* | *46* | *47* | *48* | *40* | *29* | *31* | *33* | *34* | *35* | *37* |
| Low Scenario | 74 | 83 | 85 | 90 | 91 | 92 | 94 | 95 | 96 | 97 | 98 | 99 | 100 | 76 | 62 | 63 | 64 | 65 | 66 | 67 |
| *Need - Low Scenario* | *13* | *22* | *24* | *29* | *30* | *31* | *33* | *34* | *35* | *36* | *37* | *38* | *39* | *15* | *0* | *0* | *0* | *0* | *0* | *0* |

| **Pickle Lake Subsystem** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LMC of Existing System | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| High Scenario | 31 | 35 | 35 | 44 | 44 | 52 | 53 | 55 | 57 | 60 | 62 | 64 | 66 | 69 | 71 | 73 | 76 | 78 | 81 | 83 |
| *Need - High Scenario* | *7* | *11* | *11* | *20* | *20* | *28* | *29* | *31* | *33* | *36* | *38* | *40* | *42* | *45* | *47* | *49* | *52* | *54* | *57* | *59* |
| Reference Scenario | 31 | 35 | 35 | 42 | 42 | 45 | 46 | 48 | 50 | 52 | 55 | 57 | 59 | 57 | 59 | 62 | 64 | 67 | 69 | 71 |
| *Need - Reference Scenario* | *7* | *11* | *11* | *18* | *18* | *21* | *22* | *24* | *26* | *28* | *31* | *33* | *35* | *33* | *35* | *38* | *40* | *43* | *45* | *47* |
| Low Scenario | 31 | 34 | 35 | 39 | 39 | 40 | 40 | 41 | 41 | 41 | 42 | 42 | 43 | 32 | 32 | 33 | 33 | 34 | 35 | 35 |
| *Need - Low Scenario* | *7* | *10* | *11* | *15* | *15* | *16* | *16* | *17* | *17* | *17* | *18* | *18* | *19* | *0* | *0* | *0* | *9* | *10* | *11* | *11* |

| **Ring of Fire Subsystem** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LMC of Existing System | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| High Scenario | 3 | 3 | 3 | 22 | 22 | 22 | 66 | 66 | 66 | 67 | 67 | 67 | 71 | 71 | 71 | 72 | 72 | 72 | 72 | 73 |
| *Need - High Scenario* | *3* | *3* | *3* | *22* | *22* | *22* | *66* | *66* | *66* | *67* | *67* | *67* | *71* | *71* | *71* | *72* | *72* | *72* | *72* | *73* |
| Reference Scenario | 3 | 3 | 3 | 22 | 22 | 22 | 26 | 26 | 26 | 27 | 27 | 27 | 27 | 27 | 27 | 28 | 28 | 28 | 28 | 29 |
| *Need - Reference Scenario* | *3* | *3* | *3* | *22* | *22* | *22* | *26* | *26* | *26* | *27* | *27* | *27* | *27* | *27* | *27* | *28* | *28* | *28* | *28* | *29* |
| Low Scenario | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 7 |
| *Need - Low Scenario* | *3* | *3* | *3* | *4* | *4* | *4* | *4* | *4* | *4* | *5* | *5* | *5* | *5* | *5* | *5* | *6* | *6* | *6* | *6* | *7* |

There is a near-term (present to 2018) need for additional capacity (incremental LMC) in each subsystem. The summary of capacity needs indicates that there will be need for 18 MW and up to 20 MW in the Pickle Lake subsystem, 30 MW in the Red Lake subsystem and 22 MW in the Ring of Fire subsystem in the near term.

The majority of forecast demand growth for the North of Dryden sub-region is expected to occur in the medium-term period between 2019 and 2023. This is the period when remote communities and most new mines are expected to connect their load to the system. The long term is characterized by steadily increasing demand over the remainder of the forecast period (2024 to 2033).

In the medium term, capacity needs in the Pickle Lake subsystem are forecast to be 28 MW and up to 36 MW, and up to 59 MW by the end of the planning period in 2033. In the Red Lake subsystem needs are forecast to be 44 MW and up to 62 MW in the medium term, and up to 75 MW by the end of the planning period in 2033.

The capacity need for the Ring of Fire subsystem, which includes potential mines at the Ring of Fire and the connection of five remote communities east of Pickle Lake, is driven by when and if mines connect to the transmission system. If the mines do not connect, then only the demand of the five remote communities will need to be supplied by the system. This is forecast to be 4 MW at the time of connection and up to 7 MW by the end of the planning period in 2033. If the potential Ring of Fire area mines that are considered in the load forecast develop, the capacity need for the Ring of Fire subsystem is forecast to be up to 73 MW by the end of the planning period.

The near-, medium- and long-term capacity needs of each subsystem are summarized in Table 5 below.

**Table 5: Summary of Incremental Capacity Needs by Subsystem**[20]

| Subsystem | Near-term Capacity Needs (Present to 2018 in MW) | | | Medium-term Capacity Needs (2019-2023 in MW) | | | Long-term Capacity Needs (2024-2033 in MW) | | |
|---|---|---|---|---|---|---|---|---|---|
| | High | Reference | Low | High | Reference | Low | High | Reference | Low |
| Pickle Lake | 20 | 18 | 15 | 36 | 28 | 17 | 59 | 47 | 11 |
| Red Lake | 30 | 30 | 30 | 62 | 44 | 36 | 75 | 48 | 39 |
| Ring of Fire | 22 | 22 | 4 | 67 | 27 | 5 | 73 | 29 | 7 |

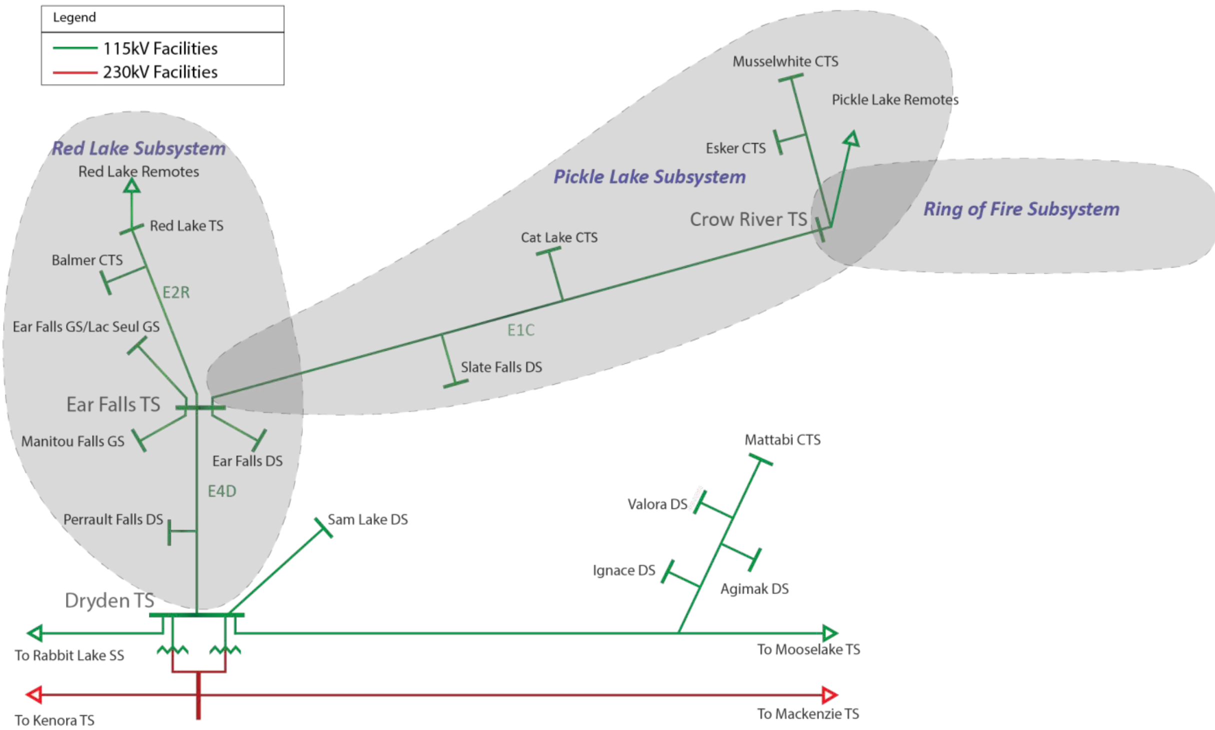
[20] Includes LMC required to supply remote communities that are economic to connect.

## 6.2 Interdependence between Subsystems

Due to the existing connection of the Pickle Lake subsystem to the Red Lake subsystem at Ear Falls, there is an existing interdependency between these subsystems. Identifying the interrelationships between subsystems is necessary because the supplying subsystem will need to have sufficient capacity to serve the needs of both subsystems. If the Pickle Lake subsystem is supplied completely by a new dedicated transmission connection, then it would be possible (and advantageous during drought conditions) to open the connection between Pickle Lake and Ear Falls (on E1C) and remove this interdependency.

Further, if the Pickle Lake subsystem has sufficient capacity in the future and the Ring of Fire subsystem is connected to Pickle Lake, then a new interdependency between the Pickle Lake and Ring of Fire subsystems would be created. These relationships are highlighted on the map below in Figure 14, which shows the amount of load in the dependent subsystem that is or would be served from the supplying subsystem. The ultimate capacity needed in the Red Lake and Pickle Lake subsystems will depend on the how the Pickle Lake and Ring of Fire subsystems are supplied in the future.

**Figure 14: North of Dryden Subsystems and Points of Intersection**

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# 7 OPTIONS AND ALTERNATIVE DEVELOPMENT

This section identifies and evaluates options for developing integrated solutions that meet the needs identified in Section 6. Options applicable for all subsystems are described first, subsystem-specific options are then discussed. The options for the Pickle Lake subsystem are then evaluated,[21] followed by those of the Red Lake subsystem and the Ring of Fire subsystem. The options for addressing the needs of the North of Dryden sub-region are divided into those that can meet near-term needs (present-2018) and those which can meet the medium- and long-term needs (2019-2033) for each subsystem. Technically viable options are identified and evaluated in the context of their ability to meet the needs of each subsystem based on cost,[22] ability to meet reliability criteria, incremental capacity enabled, and in-service date.

## 7.1 Conservation, Renewable and Distributed Generation

### *Opportunities for Further Cost Effective Conservation in the North of Dryden sub-region*

Conservation is important in managing the demand in the North of Dryden sub-region. However, the high levels of load growth anticipated for the sub-region, resulting from connection of new industrial customers and the remote communities require the incorporation of supply-side solutions such as new transmission, distribution and/or generation facilities in the near term. New industrial facilities are assumed to install relatively efficient equipment from the beginning given the inherent economic benefits and the improved codes and standards.

[21] The Pickle Lake subsystem is assessed first because of its interdependence with both Red Lake and Ring of Fire subsystems. Decisions for serving the Pickle Lake subsystem will impact the capacity needs for the Red Lake subsystem and available options for the Ring of Fire subsystem.

[22] The costs represented in this report are incremental to costs that would have otherwise been incurred for the overall Ontario power system generation capacity needs. The Ontario electricity system will require incremental generation capacity to reliably serve all Ontario customers during peak demand periods by about 2018. Generation resources developed in the North of Dryden sub-region would contribute to meeting this provincial need. Cost for generation in the North of Dryden area is represented as the incremental cost above the least-cost generation option for Ontario. Details of costing methodology can be found in Appendix 10.4.

The OPA evaluates, measures and verifies (“EM&V”) conservation program savings. Moving forward, the OPA will continue to monitor conservation achievement in the North of Dryden sub-region and look for opportunities for further cost effective conservation to address supply capacity needs of the area over the medium and long term.

In Achieving Balance: Ontario’s Long-Term Energy Plan (“LTEP 2013”), the government established a provincial Conservation and Demand Management (“CDM”) target of 30 TWh in 2032. To assist the government in achieving this target, LTEP 2013 also committed to establishing a new six-year Conservation First Framework beginning in January 2015. Meeting these targets was included in establishing the needs described in Section 6. These targets apply to currently grid-connected communities and customers. The Conservation included in the net demand forecast for each subsystem is provided in Table 6 below. For remote communities, conservation opportunities are considered in more detail in the Remote Community Connection Plan.

**Table 6: Forecasted Conservation Savings in North of Dryden Sub-Region**

| | **2014** | **2019** | **2024** | **2029** | **2033** |
|---|---|---|---|---|---|
| **Pickle Lake Subsystem** | 0.1 MW | 0.5 MW | 1.2 MW | 2.0 MW | 2.6 MW |
| **Red Lake Subsystem** | 0.2 MW | 1.1 MW | 2.6 MW | 4.0 MW | 5.3 MW |
| **Ring of Fire Subsystem** | 0.0 MW | 0.2 MW | 0.4 MW | 0.7 MW | 0.9 MW |

It is anticipated that the energy efficiency savings identified in Table 6 above will be achieved mainly through measures aimed at the current load base and the load added through connection of the remote communities. The 9 MW in reduced peak demand represents about a 7% reduction of load in this area. The additional mining load is expected to be built using current codes and standards and will be operating at better energy efficiency compared to older facilities. Thus it is not anticipated that the new mining load will be able to contribute much more to energy efficiency programs. Conservation forecast in the region is derived from the provincial target and is consistent with LTEP 2013.

Given the anticipated electricity demand growth, there are opportunities in the medium to long term for proponents to pursue conservation savings. The following tools and programs could be used to achieve conservation savings in the sub-region.

Recently, the OPA has received direction from the Minister of Energy pertaining to the framework for Conservation programs[23] moving forward:

1. *2015-2020 Conservation First Framework (March 31, 2014):* To remain on track to achieve Ontario's 2013 LTEP CDM target, it is forecasted that 7 TWh needs to be achieved between 2015 and 2020 through Distributor CDM programs enabled by the Conservation First Framework. In addition, transmission-connected customers will continue to have access to OPA CDM programs. The OPA is directed to coordinate, support and fund the delivery of CDM programs through Distributors to achieve a total of 7 TWh of reductions in electricity consumption between January 1, 2015 and December 31, 2020.

2. *Continuance of the OPA's Demand Response Program under IESO management (March 31, 2014):* In LTEP 2013, Ontario signaled that responsibility for existing demand response ("DR") initiatives and introduction of new DR initiatives will be transferred from the OPA to the IESO.

3. *Industrial Accelerator Program (July 25, 2014):* The 5-year Industrial Accelerator Program ("IAP") established through the March 4, 2010 ministerial direction, will conclude on June 23, 2015. The Minister has directed the OPA to deliver the IAP for the period commencing June 23, 2015 through December 31, 2020, with a CDM target of 1.7 TWh for the period.

The spirit of the directive is to provide more opportunity for Local Distribution Companies ("LDCs"), industry, and communities to participate in conservation initiatives

[23] The current framework for Conservation programs does not apply to remote communities. These communities are anticipated for connection post-2020, which is the end of the existing framework.

so a broader scope of programs is expected to be tailored to the local needs of the region.

Each LDC will develop their conservation plans and programs to demonstrate. In assisting LDCs, the OPA has launched an online Tool Kit to provide LDCs with the information and planning resources needed to design an effective CDM plan to serve their customers. One of these resources is the Regional Achievable Potential Calculator which assists the utilities in estimating potential Conservation savings in their service regions. Use of this tool can also achieve an understanding of the potential for further conservation specific to the North of Dryden sub-region.

The IAP is available to industrial customers as a means of achieving conservation savings with financial assistance from the OPA. Given that electricity demand of the industrial sector is significant in the area, this could be a good opportunity for conservation in the sub-region. Also, the IAP program expanded the eligibility to allow commercial and institutional customers. These customers can be directly connected to the grid or connected via an LDC.

Furthermore, the following programs are available to Aboriginal Communities:

- Aboriginal Conservation Program, with the aim to provide customized conservation services designed to help First Nation communities, including remote and northern communities, reduce their electricity use in residential housing, and in commercial and institutional buildings, like stores, schools and band offices. This program will be offered for one additional year (ending December 31, 2015) until such time as LDCs are able to develop a CDM program which recognizes the specific requirements of on-reserve First Nation communities as per the 2015-2020 Conservation First Framework Directive.

- Aboriginal Community Energy Plans program to support Aboriginal participation in Ontario’s energy sector by providing up to $90,000 per community in funding to First Nation or Métis communities for local energy planning activities, with remote communities being eligible for an additional $5,000.

### *Opportunities for Renewable and Distributed Generation in the North of Dryden sub-region*

A high level assessment of the cost of renewable and distributed generation resources to meet the capacity needs of the North of Dryden sub-region was completed, estimating the dependable capacity of hydroelectric (run of river), wind, and solar resources. Dependable capacity refers to the portion of the total installed capacity that can be relied upon to meet local or system peak capacity needs. This refers to 98-percentile output. Based on the dependable capacity, costs were developed for these renewable resources. Based on the cost of other local generation and transmission options that are discussed in the following sub-sections, run of river hydroelectric, wind, and solar are not cost effective solutions for meeting the needs of the North of Dryden sub-region in the near and medium-term periods.

Details of these alternative generation resources are provided in Appendix 10.3.2 and summarized below in Table 7.

**Table 7: Summary of Alternative Generation Options**

| Resource Type | Dependable Capacity | Capital Cost per MW of Dependable Capacity | Levelized Unit Energy Cost[24] | Development Duration |
|---|---|---|---|---|
| Hydroelectric (Run of River) | 15-30% | $16 M-$66 M /MW | $60-$110/MWh | 5 to 10 Years |
| Intermittent Renewables | 5-28% | $7.5 M -$100M /MW | $80-$400/MWh | 3 Years |

While run of river hydroelectric or renewable resources are not cost-effective to meet the North of Dryden sub-region peak capacity needs, there may be opportunity for proponents to develop such projects for broader Ontario supply needs in accordance

[24] Levelized Unit Energy Cost (LUEC) is a method to compare electricity system resources on a $/MWh basis, considering the costs incurred (capital, fixed, variable, fuel, etc.) and the production of energy over the lifetime of the resource, discounted appropriately. LUEC assumes that all energy generated can be delivered without transmission constraints.

with renewable policy objectives for the provincial supply mix as set in the 2013 LTEP. Additionally, the connection of remote communities may provide the opportunity to explore development opportunities in the far north, in the longer term.

The remainder of Section 7 will assess the generation and transmission options that can cost effectively meet the identified capacity needs of the North of Dryden sub-region.

## 7.2 Summary of Recommended and Assessed Options for Meeting Pickle Lake Subsystem Needs

Based on the following analysis, the OPA recommends that a new 230 kV single circuit line to Pickle Lake be built as soon as possible in order to meet the needs of the Pickle Lake subsystem. Building the new line to 230 kV standards is the most economic option to meet the reference forecast scenario, which is regarded as the most-likely scenario. A line built to 230 kV standards also mitigates the long-term risk associated with higher forecasted demand scenarios and maintains the flexibility to supply the Ring of Fire mining development from Pickle Lake. The OPA also recommends that circuit E1C be opened at Ear Falls as an operational measure when the local system is capacity constrained. This operational measure maximizes the capability of the transmission system in the area, resulting in incremental LMC to the Red Lake subsystem. The capacity constraint is expected to occur during high demand periods coincident with drought hydroelectric conditions.

The following section summarizes the analysis and comparison of options.

Within the context of the North of Dryden IRRP, the Pickle Lake subsystem is assessed first because of its interdependence with both the Red Lake subsystem and the Ring of Fire subsystem as discussed in Section 5.2. Decisions made for serving the Pickle Lake subsystem will impact the capacity needs for the Red Lake subsystem at Ear Falls TS and the options for serving the Ring of Fire subsystem.

As mentioned previously, the Pickle Lake subsystem is currently supplied by the 115 kV line E1C from Ear Falls TS and the subsystem has reached its LMC. The forecasted near-term growth and medium- to long-term growth cannot be met by the existing system and other supply options are required. Identified needs for the Pickle Lake subsystem are summarized in Table 8, below.

**Table 8: Needs for Pickle Lake Subsystem**

| Timing | Needs | Required Load Meeting Capability [MW] | | |
|---|---|---|---|---|
| | | Low | Reference | High |
| Near term (Present-2018) | ***Near term Total 1:*** *Supply Mining and Community Demand in the Pickle Lake Subsystem, and Supply the 5 Communities in the Ring of Fire Subsystem* | ***43*** | ***46*** | ***48*** |
| Near term (Present-2018) | ***Near term Total 2:*** *Supply Mining and Community Demand in the Pickle Lake Subsystem and in the Ring of Fire Subsystem* | ***43*** | ***64*** | ***66*** |
| Medium and long term (2019-2033) | ***Medium and long term Total 1:*** *Supply Mining and Community Demand in the Pickle Lake Subsystem, and Supply the 5 Communities in the Ring of Fire Subsystem* | ***48*** | ***78*** | ***90*** |
| Medium and long term (2019-2033) | ***Medium and long term Total 2:*** *Supply Mining and Community Demand in the Pickle Lake Subsystem and in the Ring of Fire Subsystem* | ***48*** | ***100*** | ***156*** |

The following generation and transmission options have been identified to fully or partially meet these needs.

**Table 9: Summary of Options to Meet the Needs for Pickle Lake Subsystem**[25]

| Options | Capital Cost | PV Option Cost | Incremental Load Meeting Capability [MW] | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| CNG Generation at Pickle Lake[26,27] | $132 M | $294 M | 54 | $5.44 M/MW |
| 115 kV line to Pickle Lake[28] | $126 M | $80 M | 18 + 35 | $1.31 M/MW |
| 230 kV line to Pickle Lake[18] | $167 M | $106 M | 54 + 35[29] | $1.07 M/MW |
| Pre-build 230 kV line to Pickle Lake,<br>Stage 1: operate at 115 kV[18]<br>Stage 2: upgrade to 230 kV | $155 M<br>$14 M | $98 M<br>$5 M | 46 + 35<br>114 | $1.08 M/MW<br>$0.63 M/MW |

The 115 kV transmission line option would not be adequate to meet the needs of the Pickle Lake subsystem, with or without the Ring of Fire mining load supplied from Pickle Lake under the reference scenario forecasted load. The reference scenario forecast is considered the most likely scenario. The only scenario assessed that the 115 kV transmission line option would be adequate for the long term is the low scenario. The reference and high scenarios with and without the Ring of Fire mining load supplied from Pickle Lake would require a new 230 kV line.

Based on the following factors, the OPA recommends that a single circuit 230 kV line be developed as soon as possible:

- There is currently insufficient capacity to supply existing electrical demand; and
- A 115 kV line is insufficient to meet the reference scenario forecast demand, which is considered most likely, and therefore there is material risk in not meeting the long-term demand of the Pickle Lake subsystem with a 115 kV line; and

[25] Description of the method for calculating costs is provided in Appendix 10.7.1 and 0. Note all costs include reactive compensation required to meet stated LMC.
[26] Requires continued supply of 24 MW of load via E1C from Ear Falls TS
[27] Generation could be developed in 2-3 years
[28] Transmission options cannot be developed before 2016
[29] 35 MW are in the Red Lake subsystem. System is voltage limited and can reach a higher LMC with additional reactive compensation. Costing does not include reactive compensation required to supply Ring of Fire.

- A 230 kV line to Pickle Lake is required to preserve the option of supplying the Ring of Fire utilizing an East-West corridor; and
- An East-West infrastructure corridor to the Ring of Fire continues to be a viable option being considered by mining developers.

Decisions made regarding a common infrastructure corridor (e.g. transportation, etc.) to the Ring of Fire should be monitored and reflected in updates to this IRRP.

#### 7.2.1 Discussion of Options to Meet the Needs of the Pickle Lake Subsystem

Both generation and transmission options are considered for meeting the needs of the Pickle Lake subsystem. In developing these options, the economic connection of remote communities and maintaining supply options to the Ring of Fire are key planning factors.

The five remote communities in the Ring of Fire subsystem have been determined to be economic to connect in accordance with the conclusions of the Remote Community Connection Plan. The lowest cost transmission connection option for the five remote communities in the Ring of Fire subsystem, independent of the Ring of Fire mines, is to connect to Pickle Lake. Therefore, for the purposes of the IRRP, sufficient capacity would need to be made available in the Pickle Lake subsystem to connect up to five remote communities in the Ring of Fire subsystem as a minimum. Given the uncertainty around other infrastructure development plans for the Ring of Fire area, there is also long-term value in maintaining the option for Ring of Fire mines to connect at Pickle Lake. This connection could be realized utilizing an East-West multi-use corridor, which is being promoted by some mining developers in the area. Details are discussed in the following sections.

##### 7.2.1.1 Reference Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

From Table 8, this scenario requires an LMC of 46 MW for the near term, and 78 MW for the medium and long term.

### *Generation Options*

There is no existing supply of natural gas in the Pickle Lake subsystem and the OPA is not aware of any plan to expand natural gas pipeline service to Pickle Lake. However, generators fueled by Compressed Natural Gas ("CNG") could be developed in the Pickle Lake area, as CNG could be produced and transported from the TransCanada Pipelines Limited ("TCPL" or "TransCanada") mainline near Ignace to Pickle Lake along Highway 599 and beyond as needed. The cost of developing a CNG production facility at Ignace and transporting CNG from Ignace to Pickle Lake is significant and results in a much higher delivered cost of natural gas than in areas that are served by natural gas pipelines, such as Red Lake. To minimize generation costs in this option, it is assumed that the Pickle Lake subsystem will remain connected to Ear Falls TS and 24 MW of load in the Pickle Lake subsystem will continue to be served from Ear Falls TS.

The remaining 22 MW of LMC for the near term and 54 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 22 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total installed generation capacity of 47.5 MW would be required with a maximum unit size of 9.5 MW (i.e. 5x9.5 MW). Similarly, to make available 54 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total installed generation capacity of 76 MW would be required with a maximum unit size of 9.5 MW (i.e. 8x9.5 MW).

This arrangement of units would ensure that load could be supplied with up to two units unavailable by either forced or planned outages, while maintaining flows on E1C and at Ear Falls TS within thermal and voltage limits consistent with requirements outlined in ORTAC. Table 10 summarizes the gas generation capacity required and the increase in the Pickle Lake LMC it will provide.

**Table 10: Capacity of Generation Option**

| Option | Incremental LMC [MW] | Pickle Lake Subsystem LMC [MW] | Near term Reference Forecast Demand[30] [MW] | Medium and Long term Reference Forecast Demand[20] [MW] |
|---|---|---|---|---|
| Near term: 47.5 MW CNG Generation at Pickle Lake[31] | 28.5 | 52.5 | 46 | 78 |
| Medium and Long term 76 MW CNG Generation at Pickle Lake[21] | 57 | 81 | 46 | 78 |

The cost (summarized in Table 11) of supplying the growth needs of the Pickle Lake subsystem with CNG fueled generation includes any additional required voltage control devices at Pickle Lake.

**Table 11: Costs and Timing for Generation Option**

| Option | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| 47.5 MW CNG Generation at Pickle Lake | 1-2 Years | $75 M | $158 M | $6.59 M/MW |
| 76 MW CNG Generation at Pickle Lake[32] | 1-2 Years | $132 M | $294 M | $5.44 M/MW |

Generation resources in the Pickle Lake subsystem would be operated to serve local demand in the Pickle Lake subsystem in the event that load exceeds 24 MW and would likely not be dispatched in the Ontario market for supplying provincial system load due to relatively high cost of operation. At present the Ontario system has sufficient generation capacity to meet system peak and energy needs; however, by 2018 a need for additional peak capacity is forecasted. Local generation at Pickle Lake would serve demand that would otherwise be served by generation somewhere else in the system and would help to offset some of this Ontario system need.

### *Transmission Options*

[30] Includes demand for Ring of Fire remote communities (7 MW).
[31] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.
[32] Size is cumulative.

The OPA has identified three transmission options for reinforcing the supply to the Pickle Lake area.

The transmission options are:

1. A new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker on the tap line and terminating at Crow River DS in Pickle Lake.

2. A new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker on the tap line and running to Pickle Lake terminating at Crow River DS or a new TS in the Pickle Lake area with a new 230/115 kV autotransformer.

3. A new single circuit line pre-built to 230 kV standards (230 kV structures, and hardware) and initially operated at 115 kV by connecting it to M2D on the 115 kV system near Dryden with an in-line breaker on the tap line. When additional capacity is required the line would be operated at 230 kV by re-terminating on the 230 kV system near Dryden (D26A) and a 230/115 kV autotransformer would be installed at Pickle Lake.

The 230 kV line options, Options 2 or 3, are capable of supplying the reference scenario forecasted demand for the Pickle Lake subsystem including the five remote communities in the Ring of Fire subsystem until the end of the planning period.

The 115 kV line option is capable of supplying the Pickle Lake subsystem, including the five remote communities in the Ring of Fire subsystem up to a demand of 70 MW, which is the LMC of the option. This corresponds to year 2030 for the reference scenario forecasted demand.

By opening E1C at Ear Falls TS, the Red Lake subsystem no longer supplies the Pickle Lake subsystem. Under this arrangement the capacity that was allocated to the Pickle Lake subsystem (24 MW, which corresponds to 35 MW at Ear Falls due to losses), is offloaded. In other words, a new line to Pickle Lake also provides 35 MW of incremental LMC to the Red Lake subsystem. This occurs because the new line would serve the entire load along E1C. This benefit must be accounted for in the analysis.

Details of these options have been summarized in Table 12 and Table 13 below.

**Table 12: Capacity of Transmission Options**

| Transmission Options | Incremental LMC for Pickle Lake Subsystem [MW] | Incremental LMC for Red Lake Subsystem [MW] | Total Incremental LMC for Option [MW] | Pickle Lake Subsystem Load Meeting Capability [MW] | Pickle Lake Subsystem Near term Reference Forecast Demand[33] [MW] | Pickle Lake Subsystem Medium and Long term Reference Forecast Demand[33] [MW] |
|---|---|---|---|---|---|---|
| 115 kV line to Pickle Lake[34] | 46 | 35 | 81 | 70 | 46 | 78 |
| 230 kV line to Pickle Lake[35] | 136 | 35 | 171 | 160 | 46 | 78 |
| Pre-build 230 kV line to Pickle Lake[35]<br>Stage 1: operate at 115 kV<br>Stage 2: upgrade to 230 kV[35] | <br>46<br>136 | <br>35<br>35 | <br>81<br>171 | <br>70<br>160 | 46 | 78 |

[33] Includes demand for Ring of Fire remote communities (7 MW).
[34] Transmission options cannot be developed before 2016.
[35] Upgrade completed in 2023 when three Ring of Fire mines are forecast to be operating

To serve the forecasted electrical demand of the reference scenario to the end of the planning period, without any additional investments, transmission options 2 or 3, a new 230 kV single circuit line to Pickle Lake would be required.

Transmission Option 1, a 115 kV single circuit line to Pickle Lake is insufficient to meet the identified needs of the Pickle Lake subsystem, including connection of up to five remote communities in the Ring of Fire subsystem, for the reference forecast scenario beyond 2030. The reference forecast scenario load exceeds the LMC of a 115 kV single circuit line by 8 MW at the end of the planning period, in 2033.

The OPA recommends that the new line be operated at 230 kV from the onset. Deferring 230 kV operation to when the incremental capacity is required for load supply is not expected to incur any cost savings relative to initially operating at 230 kV. This is due to the fact that some additional voltage control equipment required for 115 kV operation would no longer be required after converting the line to 230 kV operation. This results in a stranded cost which is approximately equal to the deferral value.

Transmission Option 3 is the development of a 230 kV line that is staged to provide additional capacity with deferral of some capital cost to when and if the capacity is needed. This would be done by pre-building the line to 230 kV specifications but initially operating it at 115 kV. When additional capacity is required the line would be reterminated on the bulk 230 kV system on circuit D26A and a 230/115 kV autotransformer would be installed either at Crow River DS or at a new TS in Pickle Lake. As indicated above, this option is not expected to result in any relative savings compared to Transmission Option 2.

In order to properly compare costs of transmission options (which also provide incremental capacity to the Red Lake subsystem) to generation options (which do not provide incremental capacity to the Red Lake subsystem) the unit costs consider the total incremental LMC for both the Pickle Lake and Red Lake subsystems that is made available by the option. Table 13 provides a summary of costs and timing for these options.

**Table 13: Costs and Timing of Transmission Options**

| | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| 115 kV line to Pickle Lake | Not technically feasible | | | |
| 230 kV line to Pickle Lake | 3-5 Years | $167 M | $106 M | $1.07 M/MW |
| Pre-build 230 kV line to Pickle Lake<br>Stage 1: operate at 115 kV<br>Stage 2: upgrade to 230 kV[36] | <br><br>3-5 Years<br>1-2 Years | <br><br>$155 M<br>$14 M | <br><br>$98 M<br>$5 M | <br><br>$1.08 M/MW<br>$0.63 M/MW |

From the above tables, the following conclusions can be made for the forecasted load under the reference scenario *with the Ring of Fire subsystem communities supplied from Pickle Lake*:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

#### 7.2.1.2 Reference Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

The Ring of Fire subsystem reference forecasted load from mines and communities is 22 MW in the near term and 29 MW in the medium and long term. Options to supply the Ring of Fire subsystem mines include on-site generation consistent with the Environmental Assessment cases for the mining developments, as well as building a new transmission line utilizing a North-South corridor and originating from either

[36] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Marathon or east of Nipigon, or utilizing an East-West corridor originating from Pickle Lake. Detailed analysis of these options is included in 7.4. As indicated in 6.2, if the Ring of Fire subsystem is supplied from Pickle Lake utilizing an East-West corridor, interdependency between the Pickle Lake subsystem and the Ring of Fire subsystem is introduced.

The following assesses the requirements for supply to the Pickle Lake subsystem under the reference forecast scenario if the mines and communities in the Ring of Fire subsystem are supplied from Pickle Lake. The corresponding LMC required for the Pickle Lake subsystem under this reference scenario is 64 MW in the near term and 100 MW in the medium and long term as indicated by the reference scenario "*Total 2*" in Table 8.

### *Generation Options*

Generation options from the Pickle Lake subsystem to supply Ring of Fire mining load were screened out as they are less cost effective than self-generation options at the mining sites within the Ring of Fire subsystem to supply Ring of Fire mining load (which is investigated in 7.4). Therefore, only transmission options are investigated for this scenario.

### *Transmission Options*

The LMC and costs for the respective transmission options are repeated below:

**Table 14: Capacity of Transmission Options**

| Option | Incremental LMC for Pickle Lake Subsystem[1] [MW] | Incremental LMC for Red Lake Subsystem [MW] | Total Incremental LMC for Option [MW] | Pickle Lake Subsystem Load Meeting Capability[37] [MW] | Pickle Lake Subsystem Near term Reference Forecast Demand[27] [MW] | Pickle Lake Subsystem Medium and Long term Reference Forecast Demand[27] [MW] |
|---|---|---|---|---|---|---|
| 115 kV line to Pickle Lake[38] | 46 | 35 | 81 | 70 | 64 | 100 |
| 230 kV line to Pickle Lake[28] | 136 | 35 | 171 | 160 | 64 | 100 |
| Pre-build 230 kV line to Pickle Lake[28]<br>Stage 1: operate at 115 kV<br>Stage 2: upgrade to 230 kV[39] | 46<br>136 | 35<br>35 | 81<br>171 | 70<br>160 | 64 | 100 |

[37] Includes Ring of Fire subsystem.
[38] Transmission options cannot be developed before 2016.
[39] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

**Table 15: Costs and Timing of Transmission Options**

| Option | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| 115 kV line to Pickle Lake[40] | Not technically feasible | | | |
| 230 kV line to Pickle Lake | 3-5 Years | $167 M | $106 M | $1.07 M/MW |
| Pre-build 230 kV line to Pickle Lake<br>Stage 1: operate at 115 kV<br>Stage 2: upgrade to 230 kV[41] | <br>3-5 Years<br>1-2 Years | <br>$155 M<br>$14 M | <br>$98 M<br>$5 M | <br>$1.08 M/MW<br>$0.63 M/MW |

From the above tables, and consistent with the analysis in 7.2.1.1, the following conclusions can be made for the forecasted load under the reference scenario *with the Ring of Fire subsystem supplied from Pickle Lake*, including the community and mining load:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is the approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution.

This analysis reinforces the need to build a new 230 kV line to Pickle Lake, rather than a new 115 kV line.

#### 7.2.1.3 Low Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

Under the low scenario forecasted load, the LMC required is 43 MW for the near term, and 48 MW for the medium and long term as indicated by the low scenario "*Total 1*" in Table 8.

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[40] Sufficient for near term, insufficient for medium to long term.
[41] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

### *Sensitivity Analysis for Generation Options*

Similarly to what was done with the Reference Scenario analysis, in order to minimize generation cost, it is assumed that 24 MW of load in the Pickle Lake subsystem will continue to be served by the Red Lake subsystem from Ear Falls TS via the circuit E1C.

The remaining 19 MW of LMC for the near term and 24 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 19 MW or 24 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 38 MW and 47.5 MW would be required, respectively, with a maximum unit size of 9.5 MW (i.e. 4x9.5 MW and 5x9.5 MW).

**Table 16: Capacity of Generation Option**

| Option | Incremental LMC [MW] | Pickle Lake Subsystem LMC [MW] | Near term Low Forecast Demand[42] [MW] | Medium and Long term Low Forecast Demand[32] [MW] |
|---|---|---|---|---|
| Near term: 38 MW CNG Generation at Pickle Lake[43] | 19 | 43 | 43 | 48 |
| Medium and Long term 47.5 MW CNG Generation at Pickle Lake[33] | 28.5 | 52.5 | 43 | 48 |

**Table 17: Costs and Timing for Generation Option**

| Option | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| 38 MW CNG Generation at Pickle Lake | 1-2 Years | $57 M | $131 M | $6.89 M/MW |
| 47.5 MW CNG Generation at Pickle Lake | 1-2 Years | $75 M | $158 M | $6.59 M/MW |

[42] Includes demand for Ring of Fire remote communities (7 MW).
[43] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.

Based on the low forecast demand scenario, the initial near-term generation option does not change. However, less capacity is needed to meet the medium- and long-term needs compared to the reference scenario.

### *Sensitivity Analysis for Transmission Options*

Under the low forecast scenario, the LMC required for the Pickle Lake subsystem is 43 MW in the near term and 48 MW for the medium and long term. Consistent with the reference scenario, building a new line to Pickle Lake allows for a capacity increase to the Red Lake subsystem of 35 MW by opening circuit E1C from Ear Falls during capacity-constrained conditions, where peak demand is coincident with drought hydroelectric generation output.

In order to supply 43 MW in the near term and 48 MW in the medium and long term, a new line to Pickle Lake at 115 kV would be required as a minimum and would be the most economic. It should be noted that the low scenario forecast is the only scenario that the 115 kV line option is feasible; the 115 kV line option is not feasible for all other demand scenarios.

**Table 18: Capacity of Transmission Options**

| Option | Incremental LMC for Pickle Lake Subsystem [MW] | Incremental LMC for Red Lake Subsystem [MW] | Total Incremental LMC for Option [MW] | Pickle Lake Subsystem Load Meeting Capability [MW] | Pickle Lake Subsystem Near term Low Forecast Demand[44] [MW] | Pickle Lake Subsystem Medium and Long term Low Forecast Demand[34] [MW] |
| --- | --- | --- | --- | --- | --- | --- |
| 115 kV line to Pickle Lake[45] | 46 | 35 | 81 | 70 | 37 | 41 |
| 230 kV line to Pickle Lake[35] | 136 | 35 | 171 | 160 | 37 | 41 |
| Pre-build 230 kV line to Pickle Lake[35]<br>Stage 1: operate at 115 kV<br>Stage 2: upgrade to 230 kV[46] | 46<br>136 | 35<br>35 | 81<br>171 | 70<br>160 | 37 | 41 |

[44] Includes demand for Ring of Fire remote communities (7 MW).
[45] Transmission options cannot be developed before 2016.
[46] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

**Table 19: Costs and Timing of Transmission Options**

| Option | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| 115 kV line to Pickle Lake | 3-5 Years | $126 M | $80 M | $1.31 M/MW |
| 230 kV line to Pickle Lake | 3-5 Years | $167 M | $106 M | $2.12 M/MW |
| Pre-build 230 kV line to Pickle Lake<br>Stage 1: operate at 115 kV[47] | 3-5 Years | $155 M | $98 M | $1.85 M/MW |

#### 7.2.1.4 Low Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

The low scenario does not include any additional load within the planning period from the Ring of Fire area mines compared to 7.2.1.3 and therefore this scenario is identical to 7.2.1.3 and not considered further.

#### 7.2.1.5 High Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

Under the high scenario forecasted load, the LMC required is 48 MW for the near term, and 90 MW for the medium and long term as indicated by the high scenario "*Total 1*" in Table 8.

*Sensitivity Analysis for Generation Options*

Similarly to what was done with the Reference Scenario analysis, in order to minimize generation cost, it is assumed that 24 MW of load in the Pickle Lake subsystem will continue to be served by the Red Lake subsystem from Ear Falls TS via the circuit E1C.

[47] Stage 2 would not be required for the low forecast scenario without the Ring of Fire

The remaining 24 MW of LMC for the near term and 66 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 24 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 47.5 MW would be required in the near term with a maximum unit size of 9.5 MW (i.e. 5x9.5 MW). To make available 66 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 85.5 MW would be required in the near term with a maximum unit size of 9.5 MW (i.e. 9x9.5 MW).

**Table 20: Capacity of Generation Option**

| Option | Incremental LMC [MW] | Pickle Lake Subsystem LMC [MW] | Near term High Forecast Demand[48] [MW] | Medium and Long term High Forecast Demand[38] [MW] |
|---|---|---|---|---|
| Near term: 47.5 MW CNG Generation at Pickle Lake[49] | 28.5 | 52.5 | 48 | 90 |
| Medium and Long term: 85.5 MW CNG Generation at Pickle Lake[39] | 66.5 | 90.5 | 48 | 90 |

**Table 21: Costs and Timing for Generation Option**

| Option | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| 47.5 MW CNG Generation at Pickle Lake | 1-2 Years | $75 M | $158 M | $6.59 M/MW |
| 85.5 MW CNG Generation at Pickle Lake | 1-2 Years | $140 M | $317 M | $4.80 M/MW |

[48] Includes demand for Ring of Fire remote communities (7 MW).
[49] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.

### *Sensitivity Analysis for Transmission Options*

Under the high forecast scenario, the LMC required for the Pickle Lake subsystem is 48 MW in the near term and 90 MW for the medium and long term. Consistent with the reference scenario, building a new line to Pickle Lake allows for a capacity increase to the Red Lake subsystem of 35 MW by opening circuit E1C from Ear Falls during capacity-constrained conditions, where peak demand is coincident with drought hydroelectric generation output.

In order to supply 48 MW in the near term and 90 MW in the medium and long term, a new line to Pickle Lake built to 230 kV standards would be required.

**Table 22: Capacity of Transmission Options**

| Option | Incremental LMC for Pickle Lake Subsystem [MW] | Incremental LMC for Red Lake Subsystem [MW] | Total Incremental LMC for Option [MW] | Pickle Lake Subsystem Load Meeting Capability [MW] | Pickle Lake Subsystem Near term High Forecast Demand[50] [MW] | Pickle Lake Subsystem Medium and Long term High Forecast Demand[1] [MW] |
|---|---|---|---|---|---|---|
| 115 kV line to Pickle Lake[51] | 46 | 35 | 81 | 70 | 48 | 90 |
| 230 kV line to Pickle Lake[41] | 136 | 35 | 171 | 160 | 48 | 90 |
| Pre-build 230 kV line to Pickle Lake[41]<br>Stage 1: operate at 115 kV<br>Stage 2: upgrade to 230 kV[52] | 46<br>136 | 35<br>35 | 81<br>171 | 70<br>160 | 48 | 90 |

[50] Includes 7 MW of forecast demand for the remote communities in the Ring of Fire subsystem

[51] Transmission options cannot be developed before 2016

[52] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

**Table 23: Costs and Timing of Transmission Options**

| Option | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| 115 kV line to Pickle Lake | Not technically feasible | | | |
| 230 kV line to Pickle Lake | 3-5 Years | $180 M | $114 M | $1.20 M/MW |
| Pre-build 230 kV line to Pickle Lake<br>Stage 1: operate at 115 kV<br>Stage 2: upgrade to 230 kV[53] | <br>3-5 Years<br>1-2 Years | <br>$155 M<br>$14 M | <br>$98 M<br>$5 M | <br>$1.29 M/MW<br>$0.25 M/MW |

From the above tables, and consistent with the analysis for the reference scenario, the following conclusions can be made for the forecasted load under the high scenario *with the Ring of Fire subsystem communities supplied from Pickle Lake*:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is about the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

#### 7.2.1.6 High Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

Under the high scenario forecasted load, the LMC required is 66 MW for the near term, and 156 MW for the medium and long term as indicated by the high scenario "*Total 2*" in Table 8.

[53] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

### *Sensitivity Analysis for Generation Options*

Consistent with the reference scenario analysis, generation options from the Pickle Lake subsystem to supply Ring of Fire mining load were screened out as they are less cost effective than generation options from the Ring of Fire subsystem to supply Ring of Fire mining load (which is investigated in 7.4). Therefore, only transmission options are investigated for this scenario.

### *Sensitivity Analysis for Transmission Options*

In order to supply 66 MW in the near term and 156 MW in the medium and long term, a new line to Pickle Lake built to 230 kV standards would be required. This may be achieved by either Transmission Option 2 or Option 3.

**Table 24: Capacity of Transmission Options**

| Option | Incremental LMC for Pickle Lake Subsystem [MW] | Incremental LMC for Red Lake Subsystem [MW] | Total Incremental LMC for Option [MW] | Pickle Lake Subsystem Load Meeting Capability [MW] | Pickle Lake Subsystem Near term High Forecast Demand[1] [MW] | Pickle Lake Subsystem Medium and Long term High Forecast Demand[1] [MW] |
|---|---|---|---|---|---|---|
| 115 kV line to Pickle Lake[2] | 46 | 35 | 81 | 70 | 66 | 156 |
| 230 kV line to Pickle Lake[2] | 136 | 35 | 171 | 160 | 66 | 156 |
| Pre-build 230 kV line to Pickle Lake[2]<br>Stage 1: operate at 115 kV<br>Stage 2: upgrade to 230 kV[3] | 46<br>136 | 35<br>35 | 81<br>171 | 70<br>160 | 66 | 156 |

(1) Includes 7 MW of forecast demand for the remote communities in the Ring of Fire subsystem
(2) Transmission options cannot be developed before 2016
(3) Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

**Table 25: Costs and Timing of Transmission Options**

| Options | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| 115 kV line to Pickle Lake | Not technically feasible | | | |
| 230 kV line to Pickle Lake | 3-5 Years | $180 M | $114 M | $1.20 M/MW |
| Pre-build 230 kV line to Pickle Lake<br>Stage 1: operate at 115 kV<br>Stage 2: upgrade to 230 kV[54] | <br><br>3-5 Years<br>1-2 Years | <br><br>$155 M<br>$14 M | <br><br>$98 M<br>$5 M | <br><br>$1.29 M/MW<br>$0.25 M/MW |

From the above tables, and consistent with the analysis for the reference scenario, the following conclusions can be made for the forecasted load under the high scenario *with the Ring of Fire subsystem supplied from Pickle Lake*, including the community and mining load:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need, and is only marginally sufficient to meet the near term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium-and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

### 7.2.2 **Pickle Lake Subsystem Recommended Solutions**

The OPA recommends that a new 230 kV single circuit line to Pickle Lake be built as soon as possible in order to meet the needs of the Pickle Lake subsystem. Building the new line to 230 kV standards is the most economic option to meet the reference forecast scenario, which is regarded as the most-likely scenario, and mitigates the long-term risk associated with higher forecasted demand scenarios and maintains the flexibility to supply the Ring of Fire mining development from Pickle Lake. The OPA also recommends that circuit E1C be opened at Ear Falls as an operational measure when

54 Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

the local system is capacity-constrained. This operational measure maximizes the capability of the transmission system in the area, resulting in incremental LMC to the Red Lake subsystem. The capacity constraint is expected to occur during high demand coincident with drought hydroelectric conditions.

It is recommended that development work on a new 230 kV single circuit line to Pickle Lake is completed as soon as possible. The OPA understands that preliminary development work has been started by two First Nations-owned transmission development companies. This work was initiated after the project was identified as a priority transmission project in the Government of Ontario's 2010 and 2013 Long-Term Energy Plans, and was identified for inclusion in future power system plans in the Minister of Energy's 2011 SMD to the OPA.

Implementation of the new line to Pickle Lake continues to be supported by the OPA. The OPA is following the development process for the two development companies closely. The OPA expresses urgency in the need for a new 230 kV single circuit line to Pickle Lake and will support this project to obtain the necessary approvals as soon as possible.

## 7.3 Summary of Recommended and Assessed Options for Meeting Red Lake Subsystem Needs

The OPA recommends the upgrading of circuits E4D and E2R from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. The upgrading of E4D and E2R, in addition to a new line to Pickle Lake coupled with operating circuit E1C open at Ear Falls would provide an additional 70 MW of LMC, bringing the LMC for the Red Lake subsystem to 130 MW. The LMC of 130 MW meets the needs of the Red Lake subsystem for the long term for all the OPA's forecast scenarios, beyond the planning period for the low scenario and reference scenario (which is considered the most likely), and until 2030 for the high scenario.

In addition, the OPA recommends that the IESO and Ontario Power Generation ("OPG"), with assistance from the OPA, negotiate a new contract for amended reactive services contract for Manitou Falls GS if it is beneficial to the rate payer. Based on information provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices. Table 62 in Appendix 10.6 outlines the cash-flows associated with the circuit upgrades including the station costs being referred to above.

The OPA also recommends that the potential long-term options of incremental natural gas-fired generation at Red Lake or a new transmission line be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region. This analysis will consider an updated forecast. The economics of additional gas-fired generation compared to a new transmission line will depend on the amount of load that materializes – gas generation is scalable, while transmission has greater economies of scale if enough demand is present for a sufficient level of utilization. Re-evaluating options in future planning cycles is consistent with OEB requirements in the Transmission System Code, Distribution System Code and the OPA license.

The following section summarizes the analysis and comparison of options.

As mentioned previously, the Red Lake subsystem is currently supplied by the 115 kV line E4D from Dryden TS as well as local run of river hydroelectric generation around Ear Falls. At present the subsystem has reached its LMC. Therefore, forecasted near term growth and medium and long term growth cannot be met by the existing system and other supply options are required. Identified needs for the Red Lake subsystem are summarized in Table 26, below.

**Table 26: Needs for Red Lake Subsystem**

| Timing | Needs | Required Load Meeting Capability [MW] | | |
|---|---|---|---|---|
| | | Low | Reference | High |
| Near term (2014-2018) | • Supply of mining and community demand in the Red Lake subsystem | 91 | 91 | 91 |
| | ***Total Near term*** | ***91*** | ***91*** | ***91*** |
| Medium and long term (2019-2033) | • Supply of mining and community demand in the Red Lake subsystem | 100 | 109 | 136 |
| | ***Total Medium and Long term*** | ***100*** | ***109*** | ***136*** |

The following near term generation and transmission options have been identified for meeting these needs.

**Table 27: Summary of Options to Meet the Near-term Needs of the Red Lake Subsystem**

| Options to Meet Near-term Needs | Capital Cost | PV Cost | Incremental Load Meeting Capability | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| Red Lake Gas Generation (30 MW) | $89 M | $51 M | 30 MW | $1.94 M/MW |
| Off Load E1C to New Line to Pickle Lake[55] | $66 M | $42 M | 35 MW | |
| Upgrade E4D and E2R | $16 M | $11 M | 34 MW | $1.11 M/MW[56] |
| Off Load E1C to New Line to Pickle Lake | $66 M | $42 M | 35 MW | |

The OPA recommends upgrading E4D and E2R, as this option has the lowest NPV cost for meeting the near-term needs of the Red Lake subsystem. This option also has the shortest lead time and the highest incremental capacity.

[55] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[56] Note that utilized capacity is 30 MW in the near term.

**Table 28: Summary of Options to Meet the Medium- and Long-Term Needs of the Red Lake Subsystem**

| Options to Meet Medium- and Long-Term Needs | Capital Cost | PV Cost[57] | Incremental Load Meeting Capability | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| Red Lake Gas Generation (30 MW)[58] | \$95 M | \$6 M | 30 MW | \$0.20 M/MW |
| Ear Falls and Red Lake Gas Generation (60 MW) | \$153 M | \$8 M | 60 MW | \$0.13 M/MW |
| Install Voltage Compensation at Ear Falls and Red Lake (130 MW) | \$9 M | \$1 M | 21 MW | \$0.05 M/MW |
| New 115 kV line to Ear Falls (160 MW) | \$91 M | \$10 M | 30 MW | \$0.34 M/MW |
| New 115 kV line to Ear Falls (190 MW) | \$108 M | \$12 M | 60 MW | \$0.20 M/MW |
| New 230 kV line to Ear Falls (190 MW) | \$132 M | \$15 M | 60 MW | \$0.25 M/MW |

Once the upgrades to E4D and E2R are complete and the new line to Pickle Lake is in service, the Red Lake subsystem will have an LMC of 130 MW, which is sufficient to meet the supply needs of the Red Lake subsystem for the long term.

Costs do not need to be incurred at this time for additional enhancements for the Red Lake subsystem beyond E4D and E2R upgrades. Under the low scenario and reference scenario (which is considered most likely) no incremental LMC is required beyond 130 MW. Only under the high scenario is incremental LMC forecasted to be required in 2030. The lead times for the long-term incremental options allow for re-evaluation of the demand forecast and options in future planning cycles. Future planning cycles will contain more certainty in the demand forecast as mines and related development materialize. The next planning cycle for the North of Dryden sub-region is between 1-5

[57] Present Value costs for long-term options consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until about 2030 at earliest, and therefore only 3 years of costs discounted over 17 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

[58] Same as the near term option, with install date of 2030 and therefore cannot be combined with the near term option.

years, as per the OEB-sanctioned regional planning process. The prudent course of action for the long term is monitoring load growth and re-evaluating in a timely manner.

### 7.3.1 Discussion of Options to Meet the Needs of the Red Lake Subsystem

Both generation and transmission options are considered for meeting the needs of the Red Lake subsystem.

The following sub-sections will outline the evaluation of various integrated options to meet the near-term and medium-to long-term needs of the Red Lake subsystem for the reference, low, and high load forecast scenarios.

#### 7.3.1.1 Reference Scenario Options Analysis for Red Lake Subsystem

Under the reference scenario, the LMC required is 91 MW for the near term, and 109 MW for the medium and long term as indicated by the reference scenario in Table 26. The existing LMC for the Red Lake subsystem is 61 MW, which is not sufficient.

In establishing the need for incremental LMC for the Red Lake subsystem, it is assumed that, consistent with the recommendations for addressing supply needs for the Pickle Lake subsystem, a new line to Pickle Lake will be implemented and circuit E1C will be operated open at Ear Falls SS. Opening circuit E1C from Ear Falls SS relieves circuit E4D of 35 MW.

*Generation Options*

At Red Lake, there is a limited supply of natural gas on the existing Union Gas pipeline. This pipeline was extended to serve the needs of an industrial customer at Red Lake and the Town of Red Lake. Based on information provided by the industrial customer, there is sufficient pipeline capacity to increase the LMC by 30 MW from gas-fired generation at Red Lake.

The OPA studied the costs and benefits of implementing gas fired generation to provide incremental LMC in the Red Lake subsystem. The generators could operate both as a local area resource and as a system resource to support growth in northwest Ontario, by reducing loading on the bulk transmission system at Dryden TS. Gas generators in the Red Lake subsystem would be expected to operate for local area needs primarily during periods when run of river hydroelectric generation near Ear Falls is low and when the demand in the area is high.

Due to the availability of gas on the pipeline and the distribution of load in the Red Lake subsystem, gas generation at Red Lake would increase the LMC of the Red Lake subsystem by 30 MW. Table 29 summarizes the capability and Table 30 summarizes the cost and timing associated with the gas generation option.

**Table 29: Capacity for Generation Options**

| Option | Incremental LMC [MW] | Red Lake Subsystem LMC [MW] | Near term Reference Forecast Demand [MW] | Medium and Long term Reference Forecast Demand [MW] |
|---|---|---|---|---|
| Red Lake Gas Generation (30 MW) and Transfer of Pickle Lake load to new line to Pickle Lake | 30 MW | 91 MW | 91 | 109 |
| | 35 MW | 126 MW | | |

**Table 30: Costs and Timing for Generation Options**

| Option | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| Red Lake Gas Generation (30 MW) | 2 Years | $89 M | $51 M | $1.94 M/MW |
| Transfer of E1C load to new line to Pickle Lake[59] | 3-5 Years | $66 M | $42 M | |

It is important to note that the transfer of Pickle Lake load from E1C to relieve the Red Lake subsystem can be made once a new line to Pickle Lake is in service. This again

[59] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

emphasizes the urgent need to implement the new line to Pickle Lake, as it has broader benefits for incremental LMC for the Red Lake subsystem.

### *Transmission Options*

Hydro One Networks Inc. owns and operates transmission lines E4D and E2R and has confirmed that they can be upgraded from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. This upgrade increases the LMC of the Red Lake subsystem by 34 MW. To enable this higher transmission capability, additional voltage control would also be required at Ear Falls TS. Hydro One has indicated that upgrading E4D and E2R and the installation of the required voltage control devices would take two years and could be completed within the near-term period.

**Table 31: Capacity of Transmission Option**

| Option | Incremental LMC [MW] | Red Lake Subsystem LMC [MW] | Near term Reference Forecast Demand [MW] | Medium and Long term Reference Forecast Demand [MW] |
|---|---|---|---|---|
| Near-term Option | | | | |
| Upgrade E4D and E2R | 34 | 95 | 91 | 109 |
| and Transfer of Pickle Lake load to new line to Pickle Lake | 35 | 130 | | |

Upgrading the transfer capability of E4D and E2R and installation of the required amount of voltage control is the recommended solution for the Red Lake subsystem. This option satisfies the reference scenario forecasted demand at the least cost. When E4D and E2R are upgraded and the required amount of voltage control is installed at Ear Falls TS, there will be 95 MW of capacity at Ear Falls TS to serve load in the Red Lake subsystem and 35 MW available to continue to serve the Pickle Lake subsystem. Once a new line to Pickle Lake is implemented and circuit E1C is operated open at Ear Falls SS, an additional 35 MW of LMC is provided to the Red Lake subsystem because currently the Pickle Lake subsystem currently requires 35 MW of supply from Ear Falls to serve 24 MW of load (due to losses). This brings the total LMC for the Red Lake subsystem to 130 MW. The combination of the line upgrades to E4D and E2R as well as a new line to Pickle Lake is expected provide enough LMC for the Red Lake subsystem until the end of the study horizon for the reference forecast scenario.

It should be noted that the incremental LMC of 35 MW provided to the Red Lake subsystem from transferring E1C load to the new line to Pickle Lake requires the E4D and E2R upgrades to be completed. Without the upgrades, E2R would limit the supply into Red Lake because E2R is not relieved from transferring E1C load (E1C transfer only relieves E4D).

This again emphasizes the urgent need to implement both the upgrades to circuits E4D and E2R, as well as the new line to Pickle Lake, as combined these solutions provide a significant increase in LMC for the Red Lake subsystem.

**Table 32: Cost and Timing of Transmission Option**

<table>
<tr><th>Options</th><th>Time to Complete</th><th>Capital Cost[60]</th><th>PV During Planning Period</th><th>PV Unit Cost of Utilized Capacity</th></tr>
<tr><td>Upgrade of E4D and E2R</td><td>1-2 years</td><td>$16 M</td><td>$11 M</td><td rowspan="2">$1.11 M/MW</td></tr>
<tr><td>Transfer of E1C load to new line to Pickle Lake[61]</td><td>3-5 years</td><td>$66 M</td><td>$42 M</td></tr>
</table>

Based on the above analysis of Generation and Transmission Options for the reference scenario, the upgrading of circuits E4D and E2R in combination with the relief provided by transferring E1C demand to a new line to Pickle Lake is the most economic solution to meet the needs of the Red Lake area. This solution would be sufficient to meet the electrical demand in the Red Lake subsystem until beyond the planning period.

[60] Capital cost does not include the capital cost for new system generation
[61] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

The IESO recently completed SIAs for three customers in the Red Lake subsystem that are interested in increasing their demand on the system. Upgrading of E4D and E2R was also identified by the IESO as the preferred solution to meet the load increase requests. The IESO's analysis is consistent with the OPA's findings.

#### 7.3.1.2 Low Scenario Options Analysis for Red Lake Subsystem

Under the low scenario, the LMC required is 91 MW for the near term, and 100 MW for the medium and long term as indicated by the low scenario in Table 26.

Consistent with the analysis performed for the reference scenario, it is assumed that a new line to Pickle Lake will be implemented and circuit E1C is operated open at Ear Falls SS, which relieves circuit E4D of 35 MW.

*Sensitivity Analysis for Generation Options*

In order to meet the required LMC for the Red Lake subsystem under the low scenario, the generation option assessed for the reference scenario remains unchanged and is therefore not sensitive to the low scenario demand. A summary of capacity and costs are repeated in the following tables for convenience:

**Table 33: Capacity for Generation Options**

| Option | Incremental LMC [MW] | Red Lake Subsystem LMC [MW] | Near term Low Forecast Demand [MW] | Medium and Long term Low Forecast Demand [MW] |
|---|---|---|---|---|
| Red Lake Gas Generation (30 MW)<br>and<br>Transfer of Pickle Lake load to new line to Pickle Lake | 30 MW | 91 MW | 91 | 100 |
| | 35 MW | 126 MW | | |

**Table 34: Costs and Timing for Generation Options**

| Option | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| Red Lake Gas Generation (30 MW) | 2 Years | $89 M | $51 M | $2.38 M/MW |
| Transfer of E1C load to new line to Pickle Lake[62] | 3-5 Years | $66 M | $42 M | |

### *Sensitivity Analysis for Transmission Options*

In order to meet the required LMC for the Red Lake subsystem under the low scenario, the transmission options assessed for the reference scenario remain unchanged and are therefore not sensitive to the low scenario demand. A summary of capacity and costs are repeated in the following tables for convenience:

**Table 35: Capacity of Transmission Option**

| Option | Incremental LMC [MW] | Red Lake Subsystem LMC [MW] | Near term Low Forecast Demand [MW] | Medium and Long term Low Forecast Demand [MW] |
|---|---|---|---|---|
| Near-term Option | | | | |
| Upgrade E4D and E2R and Transfer of Pickle Lake load to new line to Pickle Lake | 34 | 95 | 91 | 100 |
| | 35 | 130 | | |

**Table 36: Cost and Timing of Transmission Option**

| Options | Time to Complete | Capital Cost[63] | PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| Upgrade of E4D and E2R | 1-2 years | $16 M | $11 M | $1.36 M/MW |
| Transfer of E1C load to new line to Pickle Lake[64] | 3-5 years | $66 M | $42 M | |

[62] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[63] Capital cost does not include the capital cost for new system generation
[64] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

### 7.3.1.3 High Scenario Options Analysis for Red Lake Subsystem

Under the high scenario, the LMC required is 91 MW for the near term, and 136 MW for the medium and long term as indicated by the high scenario in Table 26.

Consistent with the analysis performed for the reference scenario, it is assumed that a new line to Pickle Lake will be implemented and circuit E1C is operated open at Ear Falls SS, which relieves circuit E4D of 35 MW.

#### *Sensitivity Analysis for Generation Options*

In order to meet the required LMC for the Red Lake subsystem under the high scenario, additional gas generation at Ear Falls or Red Lake would be required in the long term compared to the reference scenario. However, it should be noted that based on information from the existing industrial customer gas pipeline capacity is not available to support gas-fired generation beyond 30 MW.

The option of incremental gas generation has been assessed assuming that industrial customers may require additional natural gas supply to serve their industrial processes.

A summary of capacity and costs are summarized in the following tables:

**Table 37: Capacity for Generation Options**

<table>
<tr><th>Option</th><th>Incremental LMC [MW]</th><th>Red Lake Subsystem LMC [MW]</th><th>Near term High Forecast Demand [MW]</th><th>Medium and Long term High Forecast Demand [MW]</th></tr>
<tr><td rowspan="2">Red Lake Gas Generation (30 MW)<br><br>and<br><br>Transfer of Pickle Lake load to new line to Pickle Lake</td><td>30</td><td>91</td><td rowspan="2">91</td><td rowspan="2">136</td></tr>
<tr><td>35</td><td>126</td></tr>
<tr><td colspan="5">Incremental Long term Options</td></tr>
</table>

| | | | | |
|---|---|---|---|---|
| Incremental Potential Gas Generation at Red Lake or Ear Falls (30 MW)[65] | 30 | 156 | 91 | 136 |

**Table 38: Costs and Timing for Generation Options**

| Option | Time to Complete | Capital Cost | Total PV During Planning Period | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| Red Lake Gas Generation (30 MW) | 2 Years | $89 M | $51 M | $1.36 M/MW |
| Transfer of E1C load to new line to Pickle Lake[66] | 3-5 Years | $66 M | $42 M | |
| Incremental Potential Gas Generation at Red Lake or Ear Falls (30 MW)[67] | TBD[1] | $95 M[68] | $6 M[69] | $1.00 M/MW |

From the above, the option of 30 MW of gas-fired generation at Red Lake using existing pipeline capacity in combination with relieving circuit E4D of the E1C load following the installation of a new line to Pickle Lake would result in an LMC of 126 MW for the Red Lake subsystem. This LMC would be forecasted to be exceeded by 2027 under the high scenario.

The sensitivity analysis does not impact the decisions that are required during this planning cycle. Demand forecasts and long term options will be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region.

### *Sensitivity Analysis for Transmission Options*

In order to meet the required LMC for the Red Lake subsystem under the high scenario, the transmission options assessed for the reference scenario remain unchanged and

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[65] Contingent on new gas pipeline to serve new electricity and gas customers
[66] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[67] Contingent on new gas pipeline to serve new electricity and gas customers
[68] Capital Cost does not include pipeline costs. It is assumed that if the pipeline was needed anyway, there would be no incremental pipeline costs to incorporate generation
[69] Present Value costs for long-term options consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until 2026 at earliest, and therefore only 3 years of costs discounted over 13 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

are therefore not sensitive to the high scenario demand. A summary of capacity and costs are repeated in the following tables:

**Table 39: Capacity of Transmission Option**

| Option | Incremental LMC [MW] | Red Lake Subsystem LMC [MW] | Near term High Forecast Demand [MW] | Medium and Long term High Forecast Demand [MW] |
|---|---|---|---|---|
| Near-term Option | | | | |
| Upgrade E4D and E2R | 34 | 95 | 91 | 136 |
| and Transfer of Pickle Lake load to new line to Pickle Lake | 35 | 130 | | |
| Incremental Long-term Options | | | | |
| New 115 kV line to Ear Falls (160 MW LMC) | 30 | 160 | 91 | 136 |
| New 115 kV line to Ear Falls (190 MW LMC) | 60 | 190 | 91 | 136 |
| New 230 kV line to Ear Falls (190 MW LMC) | 60 | 190 | 91 | 136 |

**Table 40: Cost and Timing of Transmission Option**

| Options | Time to Complete | Capital Cost[70] | PV During Planning Period[71] | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| Upgrade of E4D and E2R | 1-2 years | $16 M | $11 M | $0.78 M/MW |
| Transfer of Pickle Lake load to new Line at Pickle Lake[72] | 3-5 years | $66 M | $42 M | |
| New 115 kV line to Ear Falls (160 MW LMC) | 4-7 years | $91 M | $10 M | $1.72 M/MW |
| New 115 kV line to Ear Falls (190 MW LMC) | 4-7 years | $108 M | $12 M | $2.04 M/MW |
| New 230 kV line to Ear Falls (190 MW LMC) | 4-7 years | $132 M | $15 M | $2.5 M/MW |

[70] Capital cost does not include the capital cost for new system generation

[71] Present Value costs for long-term options (i.e. all except E4D and E2R upgrades, and Transfer of Pickle Lake load to new Line at Pickle Lake) consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until 2030 at earliest, and therefore only 3 years of costs discounted over 17 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

[72] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

From the above, upgrading lines E4D and E2R (Dryden to Red Lake) in combination with relieving circuit E4D of the E1C load following the installation of a new line to Pickle Lake, an LMC of 130 MW would result for the Red Lake subsystem. This LMC would be forecasted to be exceeded by 2030 under the high scenario forecasted demand, but not under the reference scenario (which is considered most likely). Incremental transmission options are available if forecasted demand consistent with, or greater than, the high scenario is realized. This is not expected to occur until 2030 under the high scenario and beyond the planning period for the reference scenario. A recommendation for incremental enhancements in addition to the line upgrades and the new line to Pickle Lake does not need to be made at this time. Demand forecasts and long-term options will be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region.

### 7.3.2 **Cost Saving Opportunities Utilizing Existing Facilities**

OPG provided information to the OPA on voltage control capabilities of the generating units at Manitou Falls as part of their comments on the Draft North of Dryden IRRP. This information was submitted in writing on November 8th, 2013. Part of this submission indicated that the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power for voltage control during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices. Total station costs for upgrading E4D and E2R are referenced in Table 62 of Appendix 10.6.

OPA recommends that the IESO and OPG, with assistance from the OPA, negotiate a new contract or amended reactive services contract for Manitou Falls GS if it is of benefit to the rate payer.

### 7.3.3 **Red Lake Subsystem Recommended Solutions**

The OPA recommends the upgrading of circuits E4D and E2R from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. The upgrading of E4D and E2R, in addition to a new line to Pickle Lake coupled with operating circuit E1C normally open at

Ear Falls would provide an additional 70 MW of LMC, bringing the LMC for the Red Lake subsystem to 130 MW. The LMC of 130 MW meets the needs of the Red Lake subsystem for the long term for all the OPA's forecast scenarios; beyond the planning period for the low scenario and reference scenario (which is considered the most likely), and until 2030 for the high scenario.

In addition, the OPA recommends that the IESO and OPG, with assistance from the OPA, negotiate a new contract or amended reactive services contract for Manitou Falls GS if it is beneficial to the rate payer. Based on information provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices.

The OPA also recommends that the potential long-term options of incremental natural gas-fired generation at Red Lake or a new transmission line be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region. This is consistent with OEB requirements in the Transmission System Code, Distribution System Code and the OPA license.

## 7.4 Summary of Options to Meet Ring of Fire Subsystem Needs

The Ring of Fire subsystem is a large geographic area on the edge of the Hudson Bay Lowlands approximately 350 km north of Long Lac and approximately 300 km east of Pickle Lake. There are five remote First Nations ("FN") communities in the area (Eabametoong FN, Neskantaga FN, Marten Falls FN, Nibinamik FN and Webequie FN) and a proposed mine development area called the Ring of Fire, where a number of companies are developing mining claims. At present the five remote First Nations communities are supplied electricity by local diesel generators.

The OPA recommends that electricity infrastructure to supply the Ring of Fire subsystem, including the connection of the remote communities, be coordinated with other infrastructure being investigated or planned, such as transportation corridors to the communities and potential mining development. Mining development companies have indicated different transportation corridor preferences for the Ring of Fire. The OPA understands that a transportation corridor may be developed in an East-West orientation from the Pickle Lake area, or in a North-South orientation from the Nakina area. Transmission options may also utilize either an East-West corridor (originating from Pickle Lake) or a North-South corridor (originating from either Marathon or a point east of Nipigon). The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

The OPA has included transmission supply options for the Ring of Fire subsystem that are consistent with these general corridor orientations identified by mining proponents. A shared East-West or North-South transmission corridor, in alignment with a transportation corridor, could be a way to reduce overall cost and environmental impact. Mining development companies have also indicated self-generation as their electrical supply base case in their EA documentation. Consistent with the EA documentation of mining development companies, the OPA has considered self-generation as a possible option for the forecasted mining load in the Ring of Fire subsystem. The decision as to whether the mining load in the Ring of Fire subsystem is supplied by transmission or generation will ultimately lie with the mining companies as they will be the beneficiaries of a direct transmission supply. The OPA has already indicated in the Remote Community Connection plan that there is a business case for connecting the five remote communities in the vicinity of the Ring of Fire on their own merit, without the connection of the mining development. The connection of the mining development with the five remote communities creates a stronger business case for the connection of the remote communities. The OPA will continue to support the economic connection of remote communities.

The relative economics of generation versus transmission to supply mining load in the Ring of Fire subsystem depends on the amount of electrical demand that materializes. The reason for this is because transmission is generally more economic for relatively large electrical demand, while generation is scalable and generally more economic for lower levels of electrical demand. Details of the various options are explained further later in this section.

The OPA also recognizes that there may be potential for further utilization of a North-South transmission supply to the Ring of Fire subsystem through integration with supplying new growth in the Greenstone area. The detailed needs and supply options specific for new growth in the Greenstone area will be assessed as part of the Greenstone-Marathon IRRP, which may be used to supplement the findings in this IRRP.

The needs identified for the Ring of Fire subsystem are to connect the five remote communities to the provincial transmission system and to supply the potential future mines. The connection of the five remote communities cannot be completed until at least 2018, as indicated in the Remote Community Connection Report. Also, mines at the Ring of Fire are not expected to start up until 2017 at the earliest. A summary of the needs is provided in Table 41.

**Table 41: Needs for the Ring of Fire Subsystem**

| Timing | Needs | Required Load Meeting Capability [MW] | | |
|---|---|---|---|---|
| | | **Low** | **Reference** | **High** |
| Near term (2014-2018) | • Connect 5 remote communities and supply mining demand in the Ring of Fire subsystems | 4 | 22 | 22 |
| | ***Total Near term*** | ***4*** | ***22*** | ***22*** |
| Medium and long term (2019-2033) | • Connect 5 remote communities and supply mining demand in the Ring of Fire subsystems | 7 | 29 | 73 |
| | ***Total Medium and Long term*** | ***7*** | ***29*** | ***73*** |

An assessment developed for the Remote Community Connection Plan determined that up to five remote First Nation communities in the subsystem are economic to connect to the grid (see Appendices 11.2 and 11.4). As a result, all options identified for this subsystem include the connection of the five remote communities included in this subsystem.

Options to meet these requirements include:

- Connection of mines and remote communities to the transmission system; or
- Connection of the remote communities and on-site generation fueled by diesel or natural gas for the mines.

Transmission supply options being considered for the Ring of Fire subsystem include a new supply from Pickle Lake, a point east of Nipigon, or Marathon. These options were developed with the understanding that both East-West and North-South transportation corridors are being considered and linear corridor planning with electricity may provide greater economic efficiencies and reduce environmental impacts. It should also be noted that 230 kV supply to Pickle Lake is the minimum technical requirement for connecting any mining load at the Ring of Fire to Pickle Lake.

Options for supply to the Ring of Fire subsystem are summarized in Table 42 below.

**Table 42: Summary of Options to Meet the Medium- and Long-Term Needs of the Ring of Fire Subsystem[73]**

| | Capital Cost[74] | PV Cost | Utilized Capacity | PV Unit Cost of Utilized Capacity |
|---|---|---|---|---|
| Diesel Generation + Remote Connection | Low: $186 M<br>High: $277 M | Low: $456 M<br>High:$1,009 M | 29 MW<br>73 MW | $15.7 M/MW<br>$13.8 M/MW |
| CNG Generation + Remote Connection | Low: $240 M<br>High: $421 M | Low: $272 M<br>High: $480 M | 29 MW<br>73 MW | $9.37 M/MW<br>$6.58 M/MW |

[73] Transmission options routed from Pickle Lake include a prorated portion (based on the relative amount of load that would be supplied to each party) of the cost for a new 230 kV transmission line to Pickle Lake.
[74] Description of capital costs can be found in the following tables: Generation, Table 26; Transmission, Table 27

| | | | | |
|---|---|---|---|---|
| 115 kV Line from Pickle Lake to Ring of Fire | $189 M | $106 M | 29 MW | $3.64 M/MW |
| 230 kV Line from Pickle Lake to Ring of Fire | $277 M | $156 M | 73 MW | $2.14 M/MW |
| 230 kV Line from Marathon to Ring of Fire | $327 M | $175 M | 73 MW | $2.40 M/MW |
| 230 kV Line from east of Nipigon to Ring of Fire | $327 M | $175 M | 73 MW | $2.40 M/MW |

Options that are developed for the scenario that the Ring of Fire subsystem mining developments and remote communities are supplied from a transmission connection to the provincial power system assumes the cost for the transmission option with road access. The option for connecting only the remote communities from a transmission connection to the provincial power system assumes the cost for the transmission option without road access. Road access may be provided from the development of a multi-use corridor.

### 7.4.1 **Discussion of Options to Meet the Needs of the Ring of Fire Subsystem**

Currently, the electric supply of the five remote communities in the Ring of Fire subsystem is provided by local diesel generators. As discussed previously, up to five of these communities have been shown to be economic to connect to the transmission system in the Remote Community Connection Plan. Hence, for the purpose of the North of Dryden IRRP, these five communities are assumed to connect to the transmission system.

Given the timelines required to obtain approvals and to design and construct transmission facilities of this scale, the OPA has assumed that transmission options for serving remote communities would not be in service until 2018 at the earliest.

#### 7.4.1.1 Reference Scenario Options Analysis for Ring of Fire Subsystem

Under the reference scenario electrical demand forecast, the LMC required is 22 MW for the near term, and 29 MW for the medium and long term as indicated in Table 41. The existing LMC for the Ring of Fire subsystem is 0 MW, as it is currently not connected to the provincial power system.

### *Generation Options*

Two Environmental Assessment Terms of Reference published by mining developers in the Ring of Fire have included electricity supply options for on-site generation for their particular mining projects. They have identified that diesel or CNG fueled generation plants can provide sufficient capacity and energy to reliably meet their needs and can be brought into service within their mine development timelines. Assuming that a proposed all-season road would connect the Ring of Fire to the provincial highway system, the transportation of the large volumes of fuel required to operate on-site generation of this scale would be enabled.

As mentioned earlier, the five remote communities in the Ring of Fire subsystem have been identified as economic to connect to the transmission system at Pickle Lake. Should the Ring of Fire mines choose the self–generation option for their electricity needs, it is assumed that the remote communities will connect to Pickle Lake through a separate remote community connection project. This option is discussed in detail in the Remote Community Connection Plan. The cost of serving the remote communities by transmission and the Ring of Fire area mines with on-site generation are considered together as an integrated option for serving the Ring of Fire subsystem.

The OPA evaluated the feasibility and relative economics of various on-site generation options to supply the mining load. Findings indicated that reciprocating engines fueled either by diesel or natural gas could power future mines at the Ring of Fire, which is consistent with the respective EA Terms of Reference of developers. These units are available in a large range of sizes which allows for capacity to be scaled to meet a wide range of needs for individual mines initially and over time. Mine developers at the Ring of Fire have plans for transportation systems that would connect the Ring of Fire to the provincial transportation network, by either road or rail. One of these options is an all-season road from the Ring of Fire to the railway near Nakina. In order to develop cost estimates for this regional plan it is assumed that fuel would be transported to the Ring of Fire via the provincial road network to Nakina and then from Nakina to the Ring of Fire via the proposed all-season road[75].

Supplying diesel fuel to mine sites for power generators is common practice. Diesel fuel can be purchased at a number of bulk storage facilities in northwest Ontario and transported to mine sites. CNG also appears to be feasible though there are no direct examples that the OPA could reference for remote mining applications. The OPA has leveraged available public information and worked with industry to establish a reasonable set of assumptions and inputs that were used to develop cost models for both remote diesel and CNG fueled DG. The cost of fuel transportation infrastructure (trucks and trailers) required to transport both diesel and CNG to the mine sites has been included in the cost analysis.

The infrastructure required to fuel a natural gas generation facility at the Ring of Fire would include a compression station located along the TCPL mainline with road access to the proposed all-season road to the Ring of Fire beginning near Nakina. Due to the complexities and permitting required to build a CNG storage facility at the mine site, the OPA understands that no CNG storage facilities are planned for the mine sites and that fuel would be delivered on a just in time basis, with allowance for only a few trailers to be kept on site. Each trailer stores approximately 2 hours supply of fuel.

While the process is not substantially different from the transport and use of diesel, there are more steps and facilities required to compress, transport and decompress the gas before it can be used. Without significant on-site storage facilities, natural gas transportation logistics will be more challenging particularly during inclement weather when the all-season road may be closed for extended periods. To account for such challenges, it is likely that the generators will have to be capable of using both diesel and natural gas. Mines will have large scale diesel storage on site to fuel their vehicles and heavy equipment which could be used to fuel the generators when natural gas

[75] The OPA does not have expertise in transportation planning; this assumption is solely for developing cost estimates for generation OM&A and does not indicate a preference of the OPA.

supply is interrupted. The OPA has also discussed the results of its CNG cost model with industry to ensure the findings are reasonable.

Liquefied natural gas ("LNG") may also be a feasible option to fuel generators. However, it is not clear what minimum production volume is required to establish a natural gas liquefaction facility in northwest Ontario or what the economics of such facilities would be. As a result, the OPA does not have sufficient information to assess either the feasibility or the economics of LNG at this time.

**Table 43: Generation Options at the Ring of Fire Mines**

| Options for Mining Load | Mining Generation [MW] | Near term Reference Forecast Demand (Mines Only) [MW] | Medium and Long term Reference Forecast Demand (Mines Only) [MW] |
|---|---|---|---|
| Diesel Generation | 22 | 18 | 22 |
| CNG Generation | 22 | | |

From the above, in order to meet the reference scenario demand for the Ring of Fire mining load, up to 22 MW of diesel or CNG generation are considered.

The costs for supplying the forecasted Ring of Fire subsystem mining load by either 22 MW of diesel or CNG generation at the Ring of Fire mines are summarized in Table 44.

**Table 44: Generation Options at the Ring of Fire Mines**

| Options for Mining Load | Mining Generation [MW] | Initial Capital Cost | Average Annual Fuel and O&M | Total PV |
|---|---|---|---|---|
| Diesel Generation | 22 | $72 M | $39 M | $393 M |
| CNG Generation | 22 | $127 M | $20 M | $209 M |

As discussed above, the integrated options for serving the needs of the remote communities and the mines in the Ring of Fire subsystem includes a transmission connection option to serve the five remote communities from Pickle Lake in the case where the Ring of Fire mines opt for self-generation. This option would consist of a 115 kV transmission line from Pickle Lake to an end point near Webequie FN, passing near Neskantaga FN. Transformer stations to serve the communities would be sited near Neskantaga FN and at the end of the line near Webequie FN. Neskantaga FN, Eabametoong FN and Marten Falls FN would be connected via distribution lines and stations to the transformer station near Neskantaga FN, while Webequie FN and Nibinamik FN would be connected by distribution lines and stations to the transformer station near Webequie FN. Figure 36 in Appendix 11.4 shows this planned connection system for the five remote communities.

The OPA has estimated the cost of connecting the five remote communities in this subsystem to be $64 million, consistent with the 2014 Remote Community Connection Plan. The costs of the integrated options for mine site generation and transmission connection of remote communities are summarized in Table 45.

**Table 45 Integrated Options for the Ring of Fire Subsystem: Mine Generation and Remote Community Connection to Pickle Lake**

| Integrated Options | PV of Mine Site Generation | PV Remote Connection | Total PV of Integrated Option |
|---|---|---|---|
| Diesel Generation + Remote Connection | $393 M | $62 M | $456M |
| CNG Generation + Remote Connection | $209 M | $62 M | $272 M |

Therefore, in order to supply the entire need for the Ring of Fire subsystem – connection of remote communities and generation supply to mines – a new 115 kV connection for remote communities and 22 MW of generation would be required and would total $273-$457 M, depending on fuel.

### *Transmission Options*

Transmission options for supplying the five remote communities and mining load at the Ring of Fire together include the following:

1. East-West corridor

    a. A new 115 kV single circuit line from Crow River DS or a new station at Pickle Lake to the Ring of Fire

    b. A new 230 kV single circuit line from a new 230/115 kV station at Pickle Lake to the Ring of Fire, and new 230/115 kV TS near Neskantaga FN

2. North-South corridor

    a. A 230 kV single circuit line from Marathon TS to a new transformer station at the Ring of Fire and a new 230/115 kV station near Marten Falls FN

    b. A 230 kV single circuit line from east of Nipigon to a new transformer station at the Ring of Fire and a new 230/115 kV station near Marten Falls FN

The LMC of these options are summarized in Table 46 below

**Table 46: Capacity of Transmission Options**

| Options | Ring of Fire Subsystem Load Meeting Capability [MW] | Ring of Fire Subsystem Near term Reference Forecast Demand [MW] | Ring of Fire Subsystem Medium and Long term Reference Forecast Demand [MW] |
|---|---|---|---|
| *East-West corridor* | | | |
| 115 kV line from Pickle Lake | 67 | 22 | 29 |
| 230 kV line from Pickle Lake | 78 | 22 | 29 |
| *North-South corridor* | | | |

| | | | |
|---|---|---|---|
| 230 kV line from Marathon TS | 78 | 22 | 29 |
| 230 kV line from east of Nipigon | 78 | 22 | 29 |

Power flow studies show that a single circuit 115 kV line from Pickle Lake could supply up to 67 MW of load at the Ring of Fire (60 MW of mining load plus 7 MW of remote community load). Figure 36 in Appendix 11.4 shows a potential configuration of the North of Dryden system with a 115 kV connection to the Ring of Fire from Pickle Lake. This would be sufficient and would be the least-cost option to supply the reference scenario forecasted demand.

It is not economic under the reference scenario forecasted demand to supply the Ring of Fire subsystem by a 230 kV transmission line.

If mining and remote community load exceeds 67 MW a new 115 kV supply would no longer be sufficient and a 230 kV connection to the Ontario transmission system is required for the Ring of Fire subsystem.

The North-South options will be assessed in further detail in the Greenstone-Marathon IRRP by considering possible economic synergies with potential load growth in the Greenstone area.

As mentioned in Section 7.4.1, the five remote communities in the Ring of Fire subsystem have been identified in the Remote Community Connection Plan as being economic to connect on their own. It is therefore assumed that if the Ring of Fire mines do not connect to the grid, then the five remote communities will continue to pursue a connection to the transmission system at Pickle Lake. The lowest cost transmission connection for these communities is a single circuit 115 kV line from Pickle Lake to a new 115/44 kV transformer station near Webequie FN.

A summary of the cost and capabilities of these options is provided in Table 47.

**Table 47: Capacity and Costs of Transmission Options**

| Options | Capital Cost | Prorated Capital of Line to Pickle Lake | Total Capital | Total PV During Planning Period |
|---|---|---|---|---|
| Remote Community Only Connection from Pickle Lake (115 kV) | $101 M | $13 M | $114 M | $62 M |
| New 115 kV line from Pickle Lake to Ring of Fire | $146 M | $44 M | $189 M | $106 M |
| New 230 kV line from Pickle Lake to Ring of Fire | $196 M | $35 M | $231 M | $127 M |
| New 230 kV Line from Marathon to Ring of Fire | $327 M | N/A | $327 M | $175 M |
| New 230 kV Line from east of Nipigon to Ring of Fire | $327 M | N/A | $327 M | $175 M |

The cost responsibility for the new line to Pickle Lake and any connection line to the Ring of Fire shared by mines and remote communities would be determined through commercial agreements and/or through the OEB's Leave to Construct application process.

### 7.4.1.2 Low Scenario Options Analysis for Ring of Fire Subsystem

Under the low scenario forecasted load, the LMC required is 4 MW for the near term, and 7 MW for the medium and long term as indicated by the low scenario in Table 41. This scenario corresponds to the load associated with only the five remote communities in the Ring of Fire subsystem.

Therefore, under this scenario, only the connection of the five remote communities is considered. As indicated in the previous section, the lowest cost transmission connection for these communities is a single circuit 115 kV line from Pickle Lake to a new 115/44 kV transformer station near Webequie FN. This is expected to cost $115 M net-present value over the planning period.

Details are included in the Remote Community Connection Report. This scenario does not require any additional consideration.

### 7.4.1.3 High Scenario Options Analysis for Ring of Fire Subsystem

Under the high scenario forecasted load, the LMC required is 22 MW for the near term, and 73 MW for the medium and long term as indicated by the high scenario in Table 41. Of the 73 MW, 66 MW is mining load and 7 MW is community load. The existing LMC for the Ring of Fire subsystem is 0 MW, as it is currently not connected to the provincial power system.

*Sensitivity Analysis for Generation Options*

In order to meet the required LMC for the Ring of Fire subsystem under the high scenario, the high generation option would be required. The tables outlining the generation options are repeated for convenience:

**Table 48: Generation Options at the Ring of Fire**

| Options for Mining Load | Mining Generation [MW] | Initial Capital Cost | Average Annual Fuel and O&M | Total PV |
|---|---|---|---|---|
| Diesel Generation | 71 | $163 M | $102 M | $946 M |
| CNG Generation | 71 | $307 M | $46 M | $418 M |

**Table 49: Integrated Option for the Ring of Fire Subsystem: Mine Generation and Remote Community Connection to Pickle Lake**

| Integrated Options | PV of Mine Site Generation | PV Remote Connection | Total PV of Integrated Option |
|---|---|---|---|
| Diesel Generation + Remote Connection | $946 M | $62 M | $1,009 M |
| CNG Generation + Remote Connection | $393 M | $62 M | $456 M |

*Sensitivity Analysis for Transmission Options*

In order to meet the required LMC for the Ring of Fire subsystem under the high scenario, the transmission options assessed for the reference scenario remain unchanged. A summary of capacity and costs are repeated in the following tables for convenience:

**Table 50: Capacity of Transmission Options**

| Options | Ring of Fire Subsystem Load Meeting Capability [MW] | Ring of Fire Subsystem Near term High Forecast Demand [MW] | Ring of Fire Subsystem Medium and Long term High Forecast Demand [MW] |
|---|---|---|---|
| *East-West corridor* | | | |
| 115 kV line from Pickle Lake | 67 | 22 | 73 |
| 230 kV line from Pickle Lake | 78 | 22 | 73 |
| *North-South corridor* | | | |
| 230 kV line from Marathon TS | 78 | 22 | 73 |
| 230 kV line from east of Nipigon | 78 | 22 | 73 |

**Table 51: Capacity and Costs of Transmission Options**

| Options | Capital Cost | Prorated Capital of Line to Pickle Lake | Total Capital | Total PV During Planning Period |
|---|---|---|---|---|
| Remote Community Only Connection from Pickle Lake (115 kV) | $101 M | $13 M | $114 M | $62 M |
| New 115 kV line from Pickle Lake to Ring of Fire | Not Technically Feasible for medium to long term | | | |
| New 230 kV line from Pickle Lake to Ring of Fire | $196 M | $35 M | $231 M | $127 M |
| New 230 kV Line from Marathon to Ring of Fire | $327 M | N/A | $327 M | $175 M |
| New 230 kV Line from east of Nipigon to Ring of Fire | $327 M | N/A | $327 M | $175 M |

As indicated previously, a 115 kV line to the Ring of Fire subsystem could supply up to 67 MW, and a 230 kV line would be required to serve demand greater than 67 MW.

Based on the high demand scenario, a 230 kV supply to the Ring of Fire subsystem would be required. A recommendation for a specific solution is not required at this time. The magnitude and timing of the potential mining load is still very uncertain, and decisions regarding transportation infrastructure to the Ring of Fire have not yet been made. A common corridor to the Ring of Fire should consider the potential need for a transmission line.

### 7.4.2 **Ring of Fire Subsystem Recommendations**

The OPA recommends that electricity infrastructure to supply the Ring of Fire subsystem is coordinated with other infrastructure being investigated, such as transportation. Transmission may also utilize either an East-West corridor (originating from Pickle Lake) or a North-South corridor (originating from either Marathon or east of Nipigon). The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

The lowest cost option for meeting the medium- and long-term identified needs is a transmission connection from either Pickle Lake, Marathon, or east of Nipigon to the Ring of Fire. The incremental cost of developing a transmission connection capable of serving mines and remote communities is substantially lower than the cost of generation to serve mines and separately connect the remote communities.

# 8 FEEDBACK FROM ENGAGEMENT AND CONSULTATION

## 8.1 Aboriginal Consultation

The OPA recognizes the importance of engaging with First Nation and Métis communities and carrying out the procedural aspects of Aboriginal consultation where delegated by the Crown.

The Ministry of Energy delegated the procedural aspects of consultation to the OPA and identified 44 First Nation communities and four Métis communities to be consulted on the Draft North of Dryden IRRP. The Ministry of Energy wrote to each community on the consultation list by letter dated April 25, 2014 to provide notice of the consultation and the delegation of the OPA's role as a delegate of the Crown. The OPA then wrote to each community by letter dated May 26, 2014 to provide the dates and locations of the consultation sessions scheduled for June 2014. The letters included the OPA's commitment to cover the cost of travel and accommodation expenses associated with attending a consultation session. OPA staff then phoned each community to follow up and to answer questions about the North of Dryden IRRP consultation and provided presentation materials in advance of all sessions. The OPA sent additional invitation letters by registered mail on September 26, 2014 for the consultation session that occurred on October 16, 2014. The OPA followed up by phoning each community to ensure that leadership and/or band staff were aware of the North of Dryden consultation.

The OPA held consultation sessions for the First Nation communities in Thunder Bay on June 18, 2014, June 25, 2014, and October 16, 2014, and in Dryden on June 26, 2014. Representatives from 15 communities attended the sessions. Two communities informed the OPA that the North of Dryden IRRP is outside their area of interest. Representatives from the Chiefs of Ontario, Grand Council Treaty 3, and Nishnawbe Aski Nation also attended the sessions but did so for informational purposes only. Notes of these sessions were prepared by the OPA and posted in the regional planning section of the OPA's website.

The OPA was in contact with the Métis Nation of Ontario ("MNO") on a number of occasions via telephone and email to set up appropriate times for regional consultation meetings with MNO's member communities. The OPA endeavoured to meet with the MNO and its chartered communities and remains open to such meetings.

The OPA met with Red Sky Métis Independent Nation on June 19 at Red Sky's office in Thunder Bay. OPA staff delivered a presentation on the North of Dryden IRRP and answered questions posed by Red Sky's representatives.

To date there have not been any specific concerns expressed regarding potential impacts of the regional plan on any Aboriginal or treaty rights. Some clarifying questions were asked during the sessions, and there were some non-consultation related questions regarding electricity rates following the connection of the remote communities identified in the Remote Community Connection Plan. At this point in time, it is not yet known how the distribution service would be structured and therefore it is not possible to determine the impact to rates in a detailed manner. Rates similar to other rural distribution customers in northwestern Ontario are believed to be expected. Other general comments included:

- the need for capacity building in communities to facilitate greater participation in consultation sessions
- some communities wish to focus on project-level consultation with proponents due to the more immediate potential impacts.

## 8.2 Municipal Engagement

Following the publication of the Draft North of Dryden IRRP, the OPA travelled across the northwest to meet with various municipal representatives from affected municipalities. The following summarizes these meetings:

**Table 52: Municipal Engagement Summary**

| Meeting Date | Municipality |
|---|---|
| December 10, 2013 | Pickle Lake |
| December 10, 2013 | Greenstone |
| December 12, 2013 | Red Lake |
| December 12, 2013 | Sioux Lookout |
| December 13, 2013 | Marathon |
| February 12, 2014 | Dryden |
| February 13, 2014 | Ignace |

Following the municipal engagement meetings, several themes emerged as common feedback from the various municipalities and mainly centered on option preference, cost responsibility, and urgency for development.

Various municipal representatives provided input that any new transmission being contemplated in northwestern Ontario should be built to 230 kV standards in order to accommodate potentially high growth and encourage economic development. In general, the OPA agrees with this philosophy if there is sufficient justification to spend the incremental cost associated with a more expensive 230 kV option compared to a less expensive 115 kV option.

The OPA considered this feedback in updating the Draft North of Dryden IRRP that was released on August 16th, 2013. In the draft IRRP, the OPA indicated that it had no preference to the voltage for the recommended new line to Pickle Lake. In this version of the IRRP, the OPA was able to find sufficient justification for initially building and operating the recommended new line to Pickle Lake to 230 kV. The justification is based on the fact that the reference scenario forecast exceeds the capability of a 115 kV line in the longer term, and the provision of option flexibility for supplying the Ring of Fire as described in Section 7.2.

Cost responsibility was another common point of feedback. Generally the municipal representatives communicated that the infrastructure being contemplated in the North of Dryden IRRP is to enable economic development. Economic development was said to provide broader benefits than the local customers and costs should therefore be shared more broadly. Cost responsibility for new transmission and distribution infrastructure will be determined by the OEB during the appropriate regulatory process. For example for applicable transmission lines, cost responsibility would be determined during the leave to construct application.

Another common theme communicated by municipal representatives was the sense of urgency to develop the near term recommendations of a new line to Pickle Lake and the line upgrades from Dryden to Red Lake. The OPA agrees that the recommendation of building a new 230 kV single circuit line to Pickle Lake and upgrading the lines between Dryden and Red Lake are required as soon as possible, and will continue to support their development within the capacity of the OPA.

## 8.3 Other Engagement Activities

Prior to the publication of the Draft North of Dryden IRRP, the OPA engaged with remote communities, municipalities, stakeholder groups and industry to better understand the needs of the North of Dryden sub-region and communicate options that the OPA was considering for the North of Dryden IRRP. Presentations were made to the following groups and events:

- Ontario Mining Conference – June, 2013
- Common Voice Northwest – May, 2013
- Kenora District Municipal Association AGM – February, 2013
- Central Corridor Energy Group/Wataynikaneyap Power – various meetings 2011-2014
- Sagatay Transmission L.P. – various meetings 2012-2014

- Sioux Lookout Aboriginal Advisory Management Board - Trades Conference Fall 2012
- Aboriginal Energy Forum – December 2012
- Keewaytinook Okimakanak Chiefs Annual Meeting – December 2012
- Red Lake Mining Forum – October 2012
- NWOFNTPC - various meetings 2011-2012

With the release of draft IRRP in August 2013, the OPA hosted a webinar on November 21, 2013 to provide a high-level overview of the plan and to start the dialogue on further developing and refining the plan. An archive of the webinar was posted to the OPA website for stakeholders and communities who were not able to participate.

The OPA also established a dedicated email address – northofdryden@powerauthority.on.ca – to receive written feedback on the draft IRRP and for correspondence about the plan.

# 9 SUMMARY OF RECOMMENDATIONS

The existing North of Dryden sub-region has met its load meeting capability. In order to accommodate the economic connection of remote First Nation communities and to enable forecasted growth in the mining sector, it is prudent to develop and implement the following recommended solutions as soon as possible:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem) and installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control devices at Pickle Lake;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. IESO/OPA to initiate discussions with OPG for new reactive power services provided by Manitou Falls GS if it is confirmed to be beneficial to the ratepayer

These recommendations are the most cost-effective options that can be implemented in a timely manner and provide flexibility for meeting a broad range of long term forecast scenarios.

The estimated combined cost of recommendations (1) and (2) during the planning period is about $124 million (net present value). Recommendation (3) may reduce the estimated cost further. Together these projects increase the LMC of the Pickle Lake subsystem from 24 MW to 160 MW, and increase the LMC of the Red Lake subsystem from 61 MW to 130 MW.

Based on the reference scenario forecast, the recommended solutions are expected to satisfy the forecasted demand requirements for the Pickle Lake and Red Lake subsystem until beyond the end of the planning period. The high scenario forecast indicates that additional investments for the Red Lake subsystem may be required by

2030. The transmission and generation options available have relatively short lead times compared to the 2030 need date, based on the high scenario forecast. As a result, no further action needs to be taken at this time.

The OPA has also shown that under all forecast scenarios assessed in this version of the North of Dryden IRRP, transmission supply options to supply the Ring of Fire subsystem are more economic than remote generation options. The OPA therefore recommends that common infrastructure corridor planning to the Ring of Fire should include the consideration of the potential need for a transmission line to ensure economic and regulatory efficiencies. The OPA will monitor developments in the Ring of Fire subsystem to ensure potential customers, stakeholders and Aboriginal groups are aware of these findings.

The OPA will continue to monitor developments in the North of Dryden sub-region, such as: progress on the recommendations in this version of the plan, demand growth, conservation activities, and progress on developments at the Ring of Fire.

As developments in the North of Dryden sub-region reach new milestones, a new planning cycle for the sub-region will be initiated. The next planning cycle will take place within the next 1-5 years, consistent with the TSC, DSC, and the OPA's license, depending on if and when currently uncertain developments take place.

When the long-term needs for the Red Lake and Ring of Fire subsystems become more certain, reinforcement projects can be triggered in the next planning cycle with appropriate lead times to ensure that the needs will be met.

Some projects may require funding by customers, in accordance with the TSC. In these cases the projects cannot proceed until customers have committed the required resources and funding for development work to be completed. Therefore, the timing of these facilities may be dependent on when customers can identify their needs and provide commitment to the project.

Additionally, conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the North of Dryden sub-region. The OPA has and will continue to actively work with existing and future customers in the North of Dryden sub-region to pursue conservation and DG. The OPA will continue to work with interested customers to understand the availability of potential resources including conservation and customer based DG in the North of Dryden sub-region.

The recommended solutions in the North of Dryden sub-region are consistent with the broader planning and development work that is underway to ensure an adequate supply is available in the Northwest as a whole.

# 10 APPENDICES

10.1 List of Remote First Nation Communities in Northwest Ontario

10.2 List of Terms and Acronyms

10.3 Planning Methodologies

10.4 Technical Studies and Analysis Methodologies

10.5 Existing System Description and It's Load Meeting Capability

10.6 Analysis of Recommended Options

10.7 Generation Options

10.8 Transmission Options

## 10.1 List of Remote First Nation Communities in the Remote Community Connection Plan

### *Pickle Lake Subsystem Communities*

- Sachigo Lake
- Bearskin Lake
- Kingfisher Lake
- Wawakepewin
- Kasabonika Lake
- Wunnumin Lake
- Wapekeka
- Kitchenuhmaykoosib Inninuwug (Big Trout Lake)
- North Caribou Lake (Weagamow)
- Muskrat Dam

### *Red Lake Subsystem Communities*

- Deer Lake
- North Spirit Lake
- Poplar Hill
- Pikangikum
- Keewaywin
- Sandy Lake

### *Ring of Fire Subsystem Communities*

- Eabametoong (Fort Hope)
- Neskantaga (Landsdowne House)
- Webequie
- Nibinamik (Summer Beaver)
- Marten Falls

### *Communities that are not Economic to Connect at this Time*

- Peawanuk
- Fort Severn
- Gull Bay
- Whitesand

## 10.2 List of Terms and Acronyms

| | |
|---|---|
| ACF | Average Capacity Factor |
| Board or OEB | Ontario Energy Board |
| C&S | Codes and Standards |
| CNG | Compressed Natural Gas |
| CTS | Customer Transformer Station |
| DG | Distributed Generation |
| DR | Demand Response |
| DS | Distribution Station |
| DSC | Distribution System Code |
| EA | Environmental Assessment |
| EE | Energy Efficiency |
| EM&V | Evaluation, Measurement & Verification |
| EUF | End Use Forecast |
| FIT | Feed-In Tariff Program |
| FN | First Nation |
| GAM | Global Adjustment Mechanism |
| GS | Generating Station |
| Hydro One or HONI | Hydro One Networks Inc. |
| IESO | Independent Electricity System Operator |
| IPSP | Integrated Power System Plan |
| IRRP | Integrated Regional Resource Plan |
| Km | Kilometers |
| kV | kilovolts |
| kW | Kilowatts |
| LDC | Local Distribution Company |
| LMC | Load Meeting Capability |
| LNG | Liquefied Natural Gas |
| LTEP | Long-Term Energy Plan of the Ministry of Energy dated November 23, 2010 |
| M | Million |
| M/MW | Million/Megawatt |
| Medium to Long term | (2019-2033) |
| MOE | Ministry of Energy |
| MTS | Municipal Transformer Station |
| MW | Megawatts |
| MWh | Megawatt hour |

| | |
|---|---|
| Near term | (2014-2018) |
| NoD | North of Dryden |
| NWOFNTPC | Northwestern Ontario First Nation Transmission Planning Committee |
| O&M | Operating & Maintenance |
| OPA | Ontario Power Authority |
| ORTAC | Ontario Resource and Transmission Assessment Criteria (IESO document) |
| PPWG | Ontario Energy Board - Planning Process Working Group's Report to the Board as part of the Renewed Regulatory Framework for Electricity |
| PV | Present Value |
| RFEI | Request for Expression of Interest |
| RoF | Ring of Fire |
| SCGT | Single Cycle Gas Turbine |
| SIA | System Impact Assessment |
| SMD | Supply Mix Directive dated February 17, 2011 |
| SPS | Special Protection Schemes |
| TCPL or TransCanada | TransCanada PipeLines Limited |
| TOR | Terms of Reference |
| TS | Transformer Station |
| TSC | Transmission System Code |

## 10.3 Study Methodologies

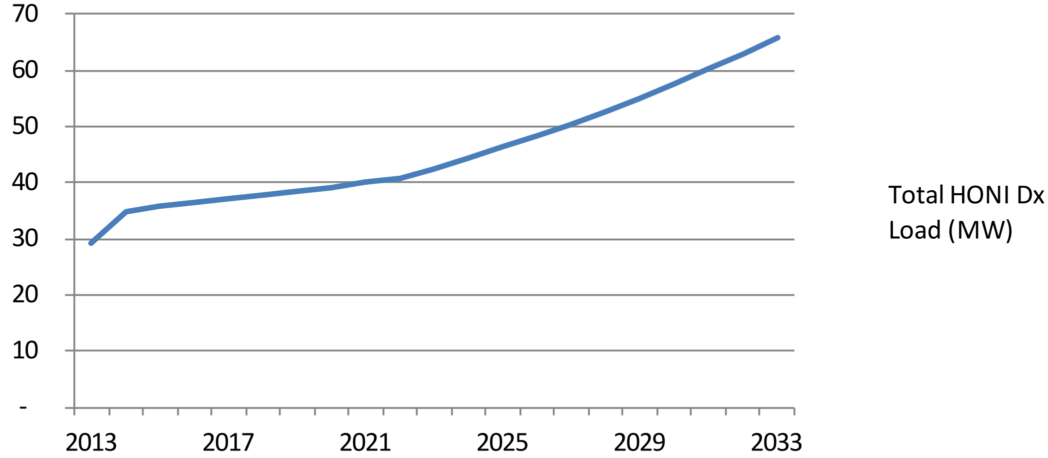
### 10.3.1 Hydro One Distribution - Reference Demand Forecast Methodology

Hydro One Distribution services the North of Dryden sub-region via six step-down stations:

- 115/12.5 kV Perrault Falls DS supplied by circuit E4D
- 115/44 kV Ear Falls TS supplied by 115 kV circuit E4D
- 115/44 kV Red Lake TS supplied by 115 kV circuit E2R
- 115/24.9 kV Cat Lake CTS supplied by 115 kV circuit E1C
- 115/24.9 kV Slate Falls DS supplied by 115 kV circuit E1C
- 115/27.6 kV Crow River DS supplied by 115 kV circuit E1C

The Hydro One reference demand forecast was developed using macro-economic analysis, which takes into account the growth of demographic and economic factors. Thus historical relationships between actual load growth and economic/demographic factors were utilized in preparing the forecast. In addition, local knowledge, as well as information regarding the loading in the area within the next two to three years, is utilized to make minor adjustments to the forecast. The forecast is net of the load impact of conservation so that it is consistent with actual load for the base-year and expected load in the future in a manner consistent with the on-going provincial conservation efforts. It also reflects the expected weather impact on peak load under average peak-time weather conditions, known as weather-normal. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast.

**Figure 15: North of Dryden sub-region Reference Distribution Demand Forecast (Net of Conservation)**




### 10.3.2 **Methodology for Dependable Renewable Generation Assumptions**

*Determining Dependable Wind and Solar Generation*

For planning purposes, the dependable capacity of generation is the prorated amount of installed generation capacity that can be relied on to meet demand during peak need hours. Since each type of distributed generation exhibits unique behavior, specific capacity contribution assumptions were used for wind and solar to determine the dependable capacity of these resource types in the North of Dryden sub-region.

**Table 53: Capacity Contributions from Wind and Solar**

| Resource Type | Capacity Contribution | Data Source |
|---|---|---|
| Wind | 30% | Wind Profiles from AWS Truepower |
| Solar | 5% | Solar Profiles from AWS Truepower |

The capacity contribution of solar generation depends on both random and predictable elements, such as weather conditions, latitude, and sunrise/sunset times. The capacity contribution of wind generation depends on weather conditions and can vary significantly. To achieve an accurate representation of these resources, hourly solar and wind profiles for the Northwest zone were estimated by AWS Truepower for the years between 2004 and 2008.

The fall period is typically the most constrained supply period for the North of Dryden sub-region as it is when hydroelectric generation in the Ear Falls area is at its lowest. To calculate the expected solar and wind output in the area, hourly capacity factors from the AWS data corresponding to the top 10% of historical demand hours during October and November were averaged. This result provides a dependable level of output that can be reasonably expected from solar and wind resources in the North of Dryden sub-region during the period of peak need.

### *Determining Dependable Hydroelectric Generation*

The hydroelectric generators located in the North of Dryden sub-region are listed below in Table 54. Lac Seul GS is an expansion of the Ear Falls GS that was undertaken by OPG with the Lac Seul First Nation.

**Table 54: Existing and Contracted Hydroelectric Generation**

| Name | Owner | No. Unit (Total) | Unit Size (MW) | Circuit |
|---|---|---|---|---|
| Manitou Falls GS | Ontario Power Generation | 5 | 4x14.9 + 1x13.5 | M3E |
| Ear Falls GS | Ontario Power Generation | 4 | 2x5.4 + 2x3.1 | Ear Falls TS bus |
| Lac Seul GS | Ontario Power Generation | 1 | 12.1 | Ear Falls TS bus |
| Trout Lake River GS | Horizon Hydro Inc. | 1 | 3.75 | E1C |

Northern hydroelectric generation is an energy limited resource known to have significantly reduced output and availability during drought conditions of the river system supplying these generating units. Neither Manitou Falls nor Ear Falls/Lac Seul are currently configured to condense. The OPA has met with OPG and are aware that configuring some select units for condense mode under drought conditions may be a low cost option to provide voltage support.

Dependable generation is defined in ORTAC as the level of generation that is available for at least 98% of hours during the evaluation period. At Manitou Falls GS, output has been at least 14.4 MW 98% of the time, while at Ear Falls GS output has been at least 6.7 MW, 98% of the time.

At Manitou Falls GS, four of the five units are connected on the secondary of one step up transformer (T1), with the fifth unit having its own transformer (T2). Because of this configuration, if T1 is unavailable, only one Manitou Falls GS unit (G5) can remain operational during the duration of the outage of T1.

The units at Manitou Falls GS units are also much larger (13.5 MW and 14.9 MW) than the Ear Falls GS units (3.1 MW and 5.4 MW), therefore the presence of one additional Ear Falls GS unit (assuming sufficient water is available during the outage of Manitou Falls T1) does not significantly improve the transfer limits in the subsystem. The single Lac Seul unit is of a similar size to the Manitou Falls GS units and its operation does significantly improve the transfer capability of the Red Lake subsystem, when it is available.

However, the performance of the Lac Seul unit and the future Trout Lake River GS during drought conditions is not yet known. Until drought condition performance is determined at these units they are assumed to be unavailable during drought conditions. The dependable generation assumptions for hydroelectric units in the Ear Falls area that have been used in this plan are summarized in Table 55.

**Table 55: Existing and Contracted Hydroelectric Generation**

| Name | No. Units (Total) | Unit Size (MW) | Dependable Output (MW) |
|---|---|---|---|
| Manitou Falls GS | 5 | 4x14.9 + 1x13.5 | 14.4 |
| Ear Falls GS | 4 | 2x5.4 + 2x3.1 | 6.7 |
| Lac Seul GS | 1 | 12.1 | 0 |
| Trout Lake River GS | 1 | 3.75 | 0 |

### *High Level Cost Assessment of Renewable Generation*

The seasonal and annual variations of run of river hydroelectric generation and the intermittent output of potential wind and solar resources in the North of Dryden sub-region lead to dependable capacities for these resources that are between 5% and 30% of their nameplate capacity, as described above. If these types of resources were used to meet capacity needs for the North of Dryden sub-region, then their dependable capacity would be used to assess their contribution to meeting peak demand. To be an alternative to other generation resources or transmission reinforcements, the nameplate capacity of these renewable resources would have to be built to a level substantially greater than the capacity required for the subsystem. Furthermore, because of this over-sizing, during times of high renewable output, these resources may be partially constrained by limited existing transmission capability connecting them to the rest of the Ontario system.

Developing these resources to serve capacity needs would require between 3 MW and 20 MW of nameplate capacity to dependably supply 1 MW of load.

It is estimated that the capital cost of dependable run of river hydroelectric capacity ranges from $15 million to $65 million per MW, while wind and solar range from $15 million to $100 million per MW. The curtailment of generation would have an associated cost, or alternatively, new implementation of transmission to deliver excess energy would also have societal costs and is an alternative to renewable generation for meeting the needs of the North of Dryden sub-region. Neither of these additional costs were considered in this high level cost analysis. A summary of the results of this cost analysis is in Table 56, below.

**Table 56: Summary of Renewable Generation Options**

| Resource Type | Firm Capacity | Capital Cost per MW of Firm Capacity | Levelized Unit Energy Cost[76] | Development Duration |
|---|---|---|---|---|
| Hydroelectric (Run of River) | 15-30% | $16 M - $66 M /MW | $60-$110/MWh | 5 to 10 Years |
| Intermittent Renewables | 5-28% | $7.5 M - $100M /MW | $80-$400/MWh | 3 Years |

## 10.4 Technical Studies and Analysis Methodologies

The following section outlines the assumptions and methodology used for performing the technical analysis for determining the load meeting capability of the existing system, and the options being considered. The load meeting capability for options being considered are mostly limited by acceptable voltage performances. Consequently, a significant portion of the costs for options being considered is for the installation of voltage control devices. When developing cost estimates, planning level unit costs were used, which typically have an accuracy of +/-50%.

### 10.4.1 Base Case Setup and Assumptions

The system studies for this plan were conducted using PSS/E Power System Simulation software. The reference PSS/E case was adapted from the base case that was produced by the IESO for the 2012 North of Dryden Feasibility Study.

*Bulk System Assumptions*

The North of Dryden sub-region is connected to the bulk transmission system at Dryden TS. The forecasted capacity requirements for the North of Dryden sub-region are coordinated with the West of Thunder Bay IRRP. Therefore, for the purpose of this assessment, it is assumed that the bulk system supply to the North of Dryden sub-

[76] Levelized Unit Energy Cost (LUEC) is a method to compare electricity system resources on a $/MWh basis, considering the costs incurred (capital, fixed, variable, fuel, etc.) and the production of energy over the lifetime of the resource, discounted appropriately. LUEC assumes that all energy generated can be delivered without transmission constraints.
.

region will be stable. A healthy supply voltage from the bulk 230 kV (nominal) system of 245 kV has been assumed.

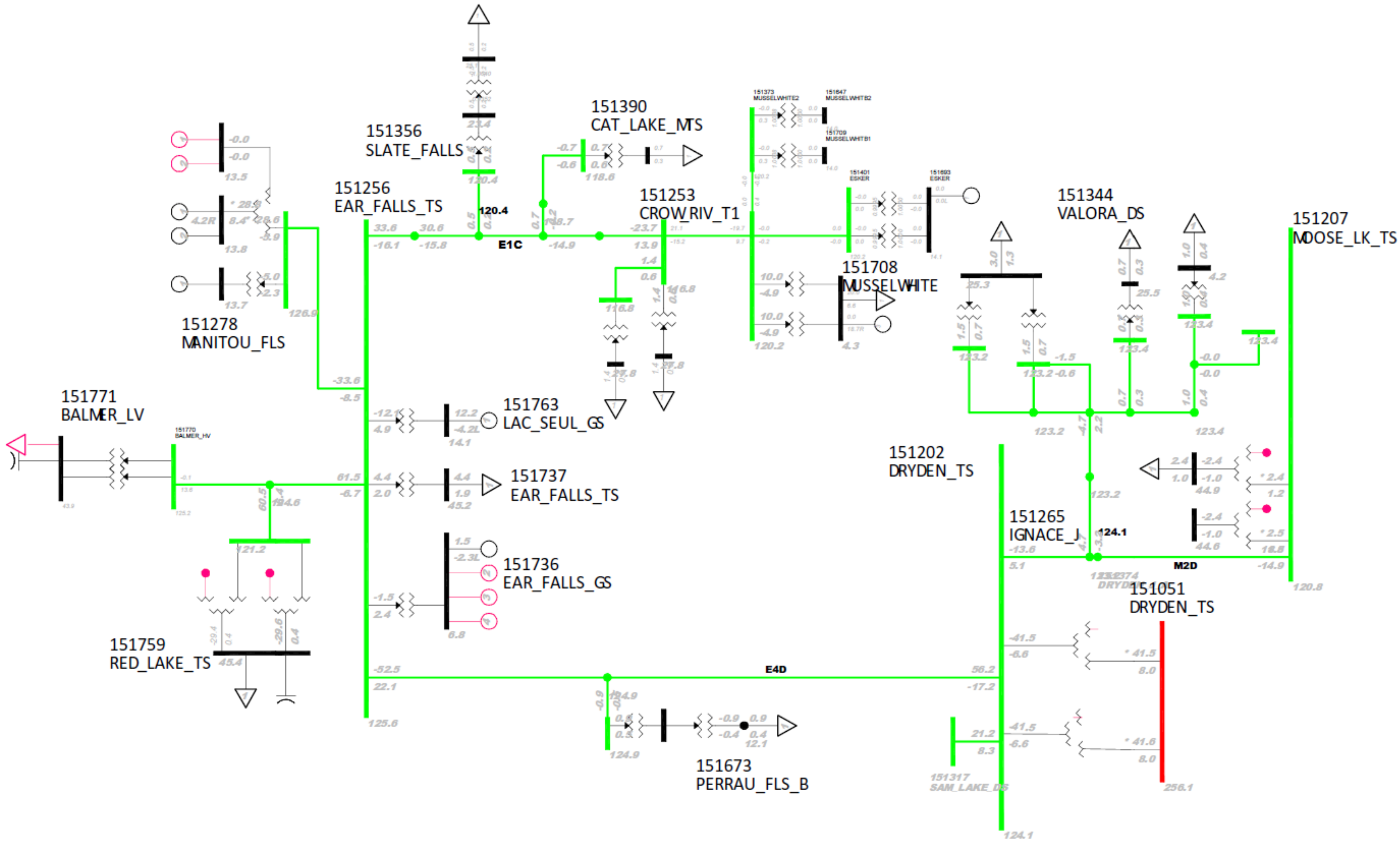
### *Local Area Assumptions*

These load flow cases include the following assumptions:

- Dependable (drought) level hydroelectric generation, which totals 21.1 MW in the Ear Falls area (Manitou Falls GS (14.4 MW), Ear Falls GS (6.7 MW))
- Summer ambient temperature of 30°C and 0-4 km/hr wind for ampacity of overhead transmission circuits
- Peak forecasted load corresponding to the reference, high, and low scenarios for the near term and medium to long term
- All proposed 115 kV circuits had line characteristics equivalent to that of a 477 kcmil ACSR conductor (similar to existing M2D), and all proposed 230 kV circuits had line characteristics equivalent to that of a 795 kcmil ACSR conductor (similar to existing circuit D26A)
- The 115 kV step-down transformers at Mc Faulds (Ring of Fire mines) were assumed to be similar to the existing transformers at Red Lake TS. Other 115 kV step-down transformers were assumed to be similar to the existing transformers at Crow River DS for loads greater than 3 MVA, or the Slate Falls transformer for loads smaller than 3 MVA. The Pickle Lake 230/115 kV autotransformer was assumed to be similar to the existing Lakehead autotransformers.
- Dependable capacity at Trout Lake River GS is assumed to be 0 MW
- 5% of installed solar capacity is assumed to be dependable. This includes four microFIT projects in Red Lake providing capacity of 39.3 kW and one microFIT project in Ear Falls with an capacity of 10 kW, providing a 2.5 kW of dependable output
- For steady state and voltage assessment, the loads are modeled as constant megavolt-ampere (MVA)
- All new voltage control devices are assumed to be Static Var Compensation (SVC) devices

- It was assumed that the loss of voltage control devices connected at load stations (McFaulds, Esker, Musselwhite, Red Lake, Balmer, Sandy Lake, Pickle Lake area Mine) would also result in the loss of the associated load.

**Figure 16: North of Dryden 2012 Peak Load Flow Case**

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### 10.4.2 **Application of IESO Planning Criteria**

In Ontario, the criteria for planning the transmission system are specified in the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)[77]. In accordance with ORTAC, the transmission system supplying a local area shall have sufficient capability under peak demand conditions to withstand specific outages prescribed by ORTAC while keeping voltages, line and equipment loading within applicable limits. In determining the load meeting capability for each subsystem, ORTAC requires certain conditions to be respected. The supply options that are discussed for the North of Dryden sub-region assume that where new lines are built parallel to existing lines, some or all of the incremental load that is enabled for connection to the system, may be curtailed in the event of a forced outage of either line. This following is an excerpt from Section 7.1 of ORTAC which states:

> "The *transmission system* must be planned to satisfy *demand* levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The *transmission system* must exhibit acceptable performance, as described below, following the design criteria contingencies defined in sections 2.7.1 and 2.7.2. For the purposes of this section, an element is comprised of a single zone of protection.
>
> With all transmission *facilities* in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.
>
> With any one element out of service3, equipment loading must be within applicable long-term *emergency* ratings, voltages must be within applicable *emergency* ranges, and transfers must be within applicable normal condition stability limits. Planned load *curtailment* or load rejection, excluding voluntary *demand* management, is permissible only to account for local generation outages. Not more than 150MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 150MW load interruption limit reflects past planning practices in Ontario."

Additionally, the following were assumed in this study to comply with ORTAC:

- Run of river hydroelectric generation should be assumed at a level that is available 98% of the time (ORTAC Section 2.6);

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[77] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

- Load power factors is assumed to be 0.95 at the low voltage busbar to comply with the Market Rule of 0.9 at the defined meter point at the HV busbar (ORTAC Section 2.4);
- Voltage operating range of 113 kV to 132 kV for the 115 kV nominal system, and 220 kV to 250 kV for the 230 kV nominal system (ORTAC Section 2.4);
- Pre-contingency voltage maintained to the greater of (ORTAC Section 4.2):
    - At least 10% margin above the instability point
    - Minimum continuous voltage pre-contingency: 113 kV for 115 kV nominal system, and 220 kV for 230 kV nominal system
    - That which results in a post-contingency voltage of at least 108 kV for 115 kV nominal system, and 207 kV for 230 kV nominal system
- All line and equipment loading is within the continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service (ORTAC Section 4.7.2 and 7.1); and
- If the subsystem has transmission connected generation, the largest generator unit is assumed to be on outage pre-contingency and not available post-contingency.

The load meeting capability for each subsystem and each option are determined with the aid of PSS/E simulation, which represents a full model of the system, accounting for active and reactive power flows, losses, voltage drops, etc.

**Table 57: Conditions for Determining Subsystem LMC**

| Local Area Supply | Conditions for LMC |
|---|---|
| Single Radial Line | Limit of the line during normal operating conditions. |
| Single Radial Line + Local Generation | Limit of the line during normal conditions; and<br>Loss of the largest generating unit. |

### 10.4.3 Technical Study Procedures

Once the needs for the subsystems were determined based on an assessment of the existing system and forecast net demand growth, the technical study identified how various options could meet the identified needs. From these needs, a range of generation and transmission options were developed that are capable of partially or fully meeting the identified needs. The capability of the options to serve the needs including the amount of voltage control required to meet the required LMC was determined.

#### *Contingencies Considered in Option Assessment*

A detailed list of the contingencies considered for the North of Dryden sub-region is outlined below in Table 58. All contingencies are limited to the loss of a single element (N-1) considering pre-contingency outage conditions consistent with ORTAC.

**Table 58: Contingencies Considered in the Technical Study**

| Subsystem | Supply Option | Contingencies |
|---|---|---|
| Pickle Lake | CNG generation at Pickle Lake | Loss of single generating unit (10 MW) at Pickle Lake |
| | | Loss of Manitou Falls GS |
| | New Line to Pickle Lake | N/A |
| Red Lake | NG generation at Red Lake | Loss of single generating unit (10 MW) at Red Lake |
| | | Loss of Manitou Falls GS |
| | New Line to Ear Falls | Loss of New Line |
| | | Loss of Manitou Falls GS |
| Ring of Fire | All | N/A |

#### *Determining Voltage Control Requirements*

For each option in each subsystem, base cases were developed for both peak and light load conditions. Each subsystem was considered independently, and the effects of each option on the bulk system around Dryden TS and/or at Marathon TS were included.

Location and size of the voltage control devices for each test case was determined under the following load scenarios to satisfy the assumptions listed above.

1. Peak load conditions, all elements in service: This test determined the voltage control devices are required to ensure sufficient margin from the voltage collapse point. Voltage control devices were used to maintain the voltage within the ranges stated in the assumptions.

2. Zero load conditions: This test determined the amount of voltage control required to manage high voltages.

3. Light load conditions, all elements in service: This test was used to determine the required switching size and range of the voltage control devices.

4. Peak load conditions, largest local element out of service: In areas where contingencies were tested, voltage control device requirements before tap changing were determined.

### *Determining Load Meeting Capability of Options*

This study uses the base cases that were developed for the peak load scenario in determining voltage control requirements, as stated above. For each subsystem, the LMC of the option following the installation of all facilities and voltage control devices that are required to meet the peak load forecast was determined for each option for each forecast scenario.

The LMCs for each option were determined using the following procedure:

1. The range of voltage control that was determined in the previous analysis was assumed to be available.

2. Peak load was assumed as a base. Thermal loading of transmission equipment was assessed.

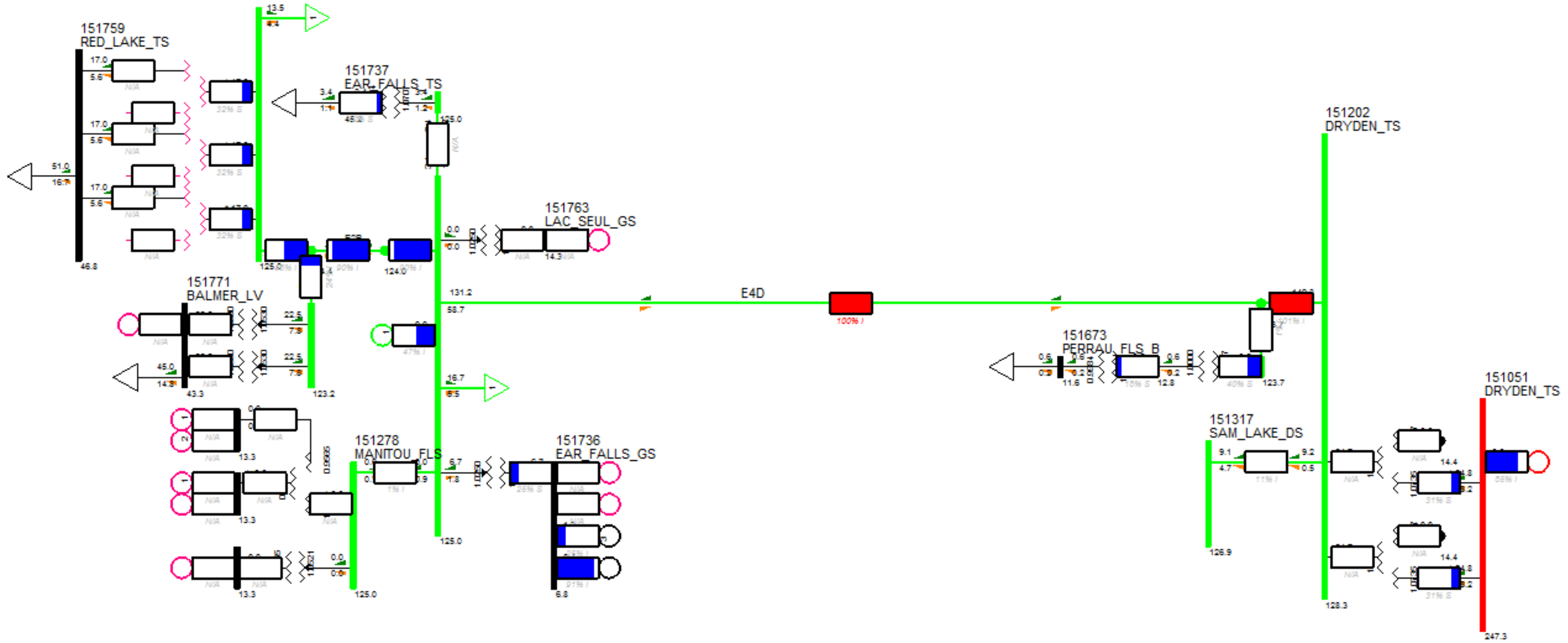
3. Where there was existing thermal capacity on transmission equipment, load was increased and new voltage control requirements were established, to determine the LMC. Load was increased at a central system bus within the subsystem (Pickle Lake area TS for the Pickle Lake subsystem, Ear Falls TS for the Red Lake subsystem, Mc Faulds TS for the Ring of Fire subsystem).

4. Following this, the system was tested allowing voltage control requirements to increase within reasonable limits.

More detailed studies for particular reinforcements may determine that voltage control devices can be located in alternative places closer to large loads, which may be found to optimize their value and reduce the overall cost. Specific connection requirements for individual customers, including requirements for additional voltage control devices will be identified by the IESO in future System Impact Assessments (“SIA”).

A sample load flow case that was used to determine the LMC of the Red Lake subsystem after the upgrade of E4D and E2R is provided in Figure 17 below. In this case, the LMC for subsystem is 130 MW.

**Figure 17: Sample of Methodology – Determining Post-Upgrade LMC of E4D and E2R Upgrade**

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## 10.5 Existing System Description and Load Meeting Capability

The North of Dryden electricity system is shown in Figure 18.

**Figure 18: Existing North of Dryden Transmission System**

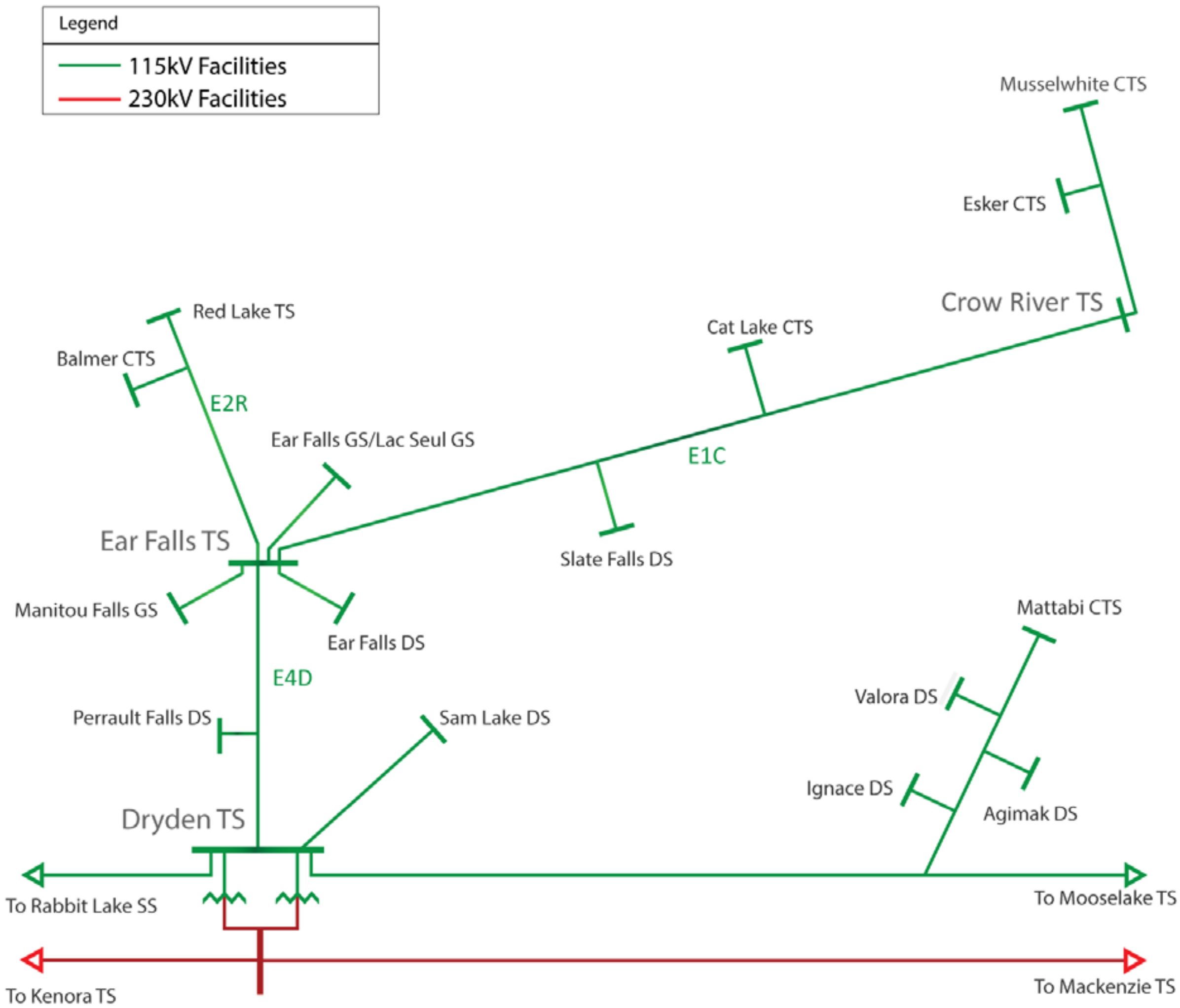


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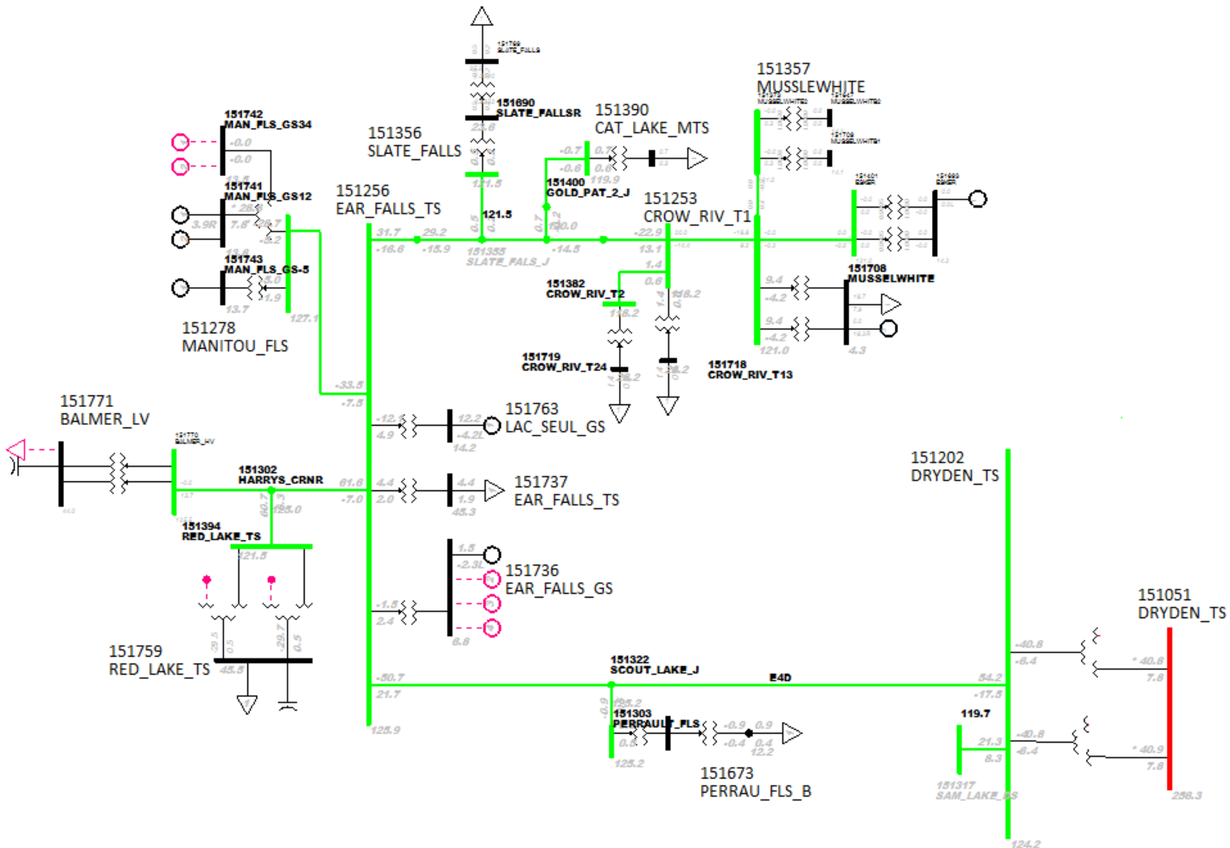
**Figure 19: Existing North of Dryden Transmission System Load Flow Plot**




## *Pickle Lake Subsystem*

The Pickle Lake subsystem includes all load currently and planned to be served by E1C at Cat Lake CTS, Slate Falls DS, Crow River DS, as well as Musselwhite mine. The Pickle Lake subsystem also includes 10 remote communities north of Pickle Lake that are planned to connect to Pickle Lake via a transmission line to Crow River DS.

Currently, the Pickle Lake subsystem has an LMC of 24 MW. Due to losses on the line E1C, supply of close to 35 MW is required from Ear Falls TS to serve this load along the line and at Pickle Lake. The LMC for the Pickle Lake subsystem is determined by the load that can be met during normal operating conditions.

### *Red Lake Subsystem*

The Red Lake subsystem includes all load and generation connected and planned to be served by E4D and E2R, at Perrault Falls DS, Ear Falls TS, Red Lake TS, Balmer CTS, and the six remote communities that lie north of Red Lake that are planned to connect to Red Lake TS. There is 102.2 MW of hydroelectric generation at Ear Falls/Lac Seul GS and at Manitou Falls GS.

Currently, the E4D and Ear Falls area generation is capable of supplying 85 MW from Ear Falls TS, which includes 61 MW in the Red Lake subsystem and 24 MW in the Pickle Lake subsystem.

### *Ring of Fire Subsystem*

The Ring of Fire subsystem includes five remote communities that are planned for connection to the provincial transmission system as well as potential future industrial customers at the Ring of Fire. This subsystem may be connected to the provincial transmission system either at Pickle Lake, Marathon TS, or east of Nipigon.

The Ring of Fire subsystem is not currently supplied from the IESO-controlled grid and thus has a load meeting capability of 0 MW. However the 5 remote communities are currently served by local diesel generation in their communities.

## 10.6 Analysis of Recommended Options

As indicated in Section 0, the recommended options for the North of Dryden sub-region are:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem) and installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control devices at Pickle Lake;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. IESO/OPA to initiate discussions with OPG for new reactive power services provided by Manitou Falls GS if it is confirmed to be beneficial to the ratepayer

   For the list of assumptions and procedure pertaining to the assessment of generation options, refer to Section 10.7. For a list of assumptions and procedure pertaining in the assessment of transmission options, refer to Section 10.8

### *Recommendation 1: New single circuit 230 kV line to Pickle Lake and supporting facilities*

The following table outlines the load meeting capability provided by the option and the long-term forecasted load.

**Table 59: Summary of Load Meeting Capability of Recommendation**

| Recommendation | Incremental Capacity | Load Meeting Capability | Low Forecast Demand | Reference Forecast Demand | High Forecast Demand |
|---|---|---|---|---|---|
| 230 kV line to Pickle Lake | 136 MW | 160 MW | 48 MW | 78 MW (100 MW) | 90 MW (156 MW) |

Table 60 outlines the cash flows used for the net present value economic analysis. Figure 20 and Figure 21 illustrate the single line diagram of the option and the power flow simulation for the reference scenario.

**Table 60: Summary of Cashflow for New Line to Pickle Lake at 230 kV**[78]

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line cost** | | | | 138 | | | | | | | | | | | | | | | | |
| **Station cost** | | | | 28.4 | | | | | | | | | | | | | | | | |
| **O&M** | | | | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 |
| **Total Annual Cost** | 0.0 | 0.0 | 0.0 | 168.3 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 |
| **Annual Amortized Cost** | | | | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 |
| **Cumulative PV** | 0.0 | 0.0 | 0.0 | 8.4 | 16.4 | 24.1 | 31.5 | 38.7 | 45.5 | 52.1 | 58.5 | 64.6 | 70.5 | 76.1 | 81.5 | 86.8 | 91.8 | 96.6 | 101.2 | 105.7 |

[78] Includes compensation required to supply Reference load forecast scenario (78 MW in 2033).

**Figure 20: New 230 kV line to Pickle Lake Diagram**

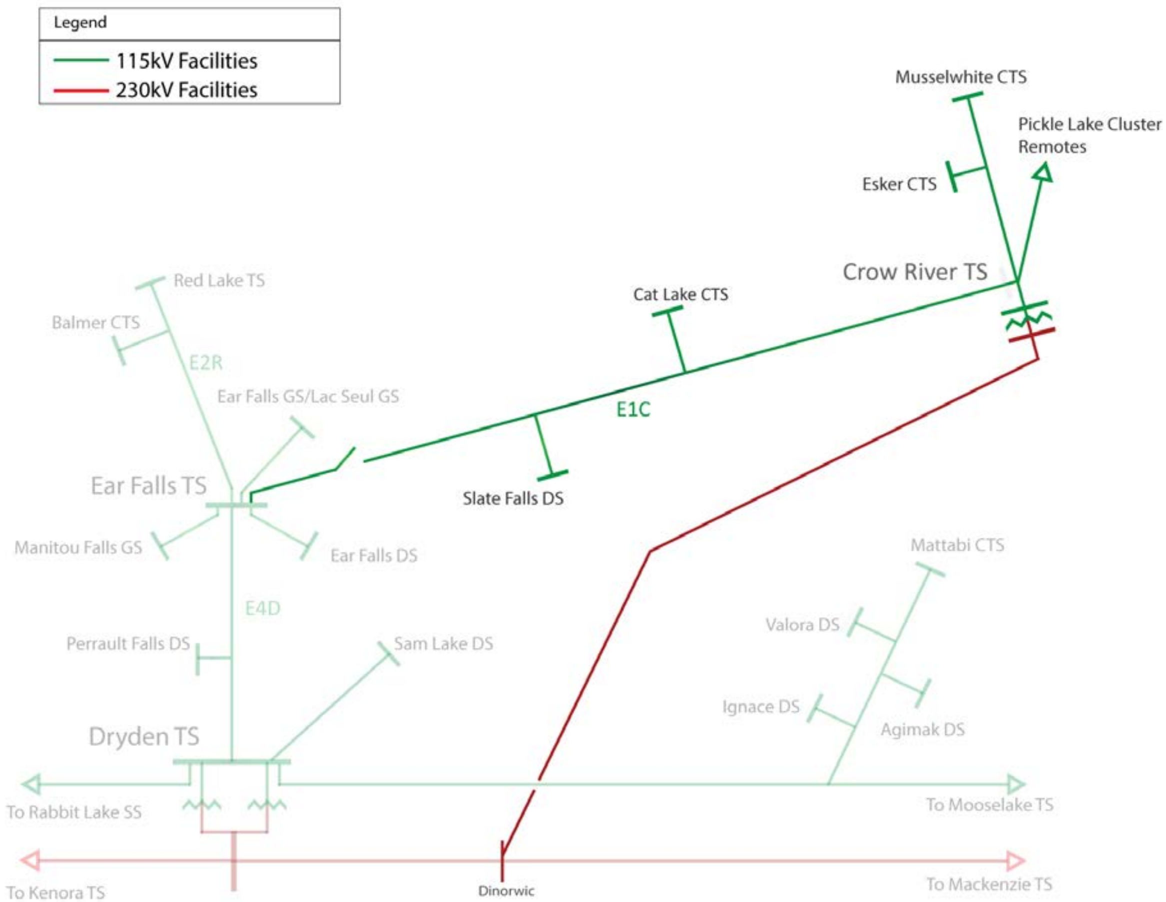



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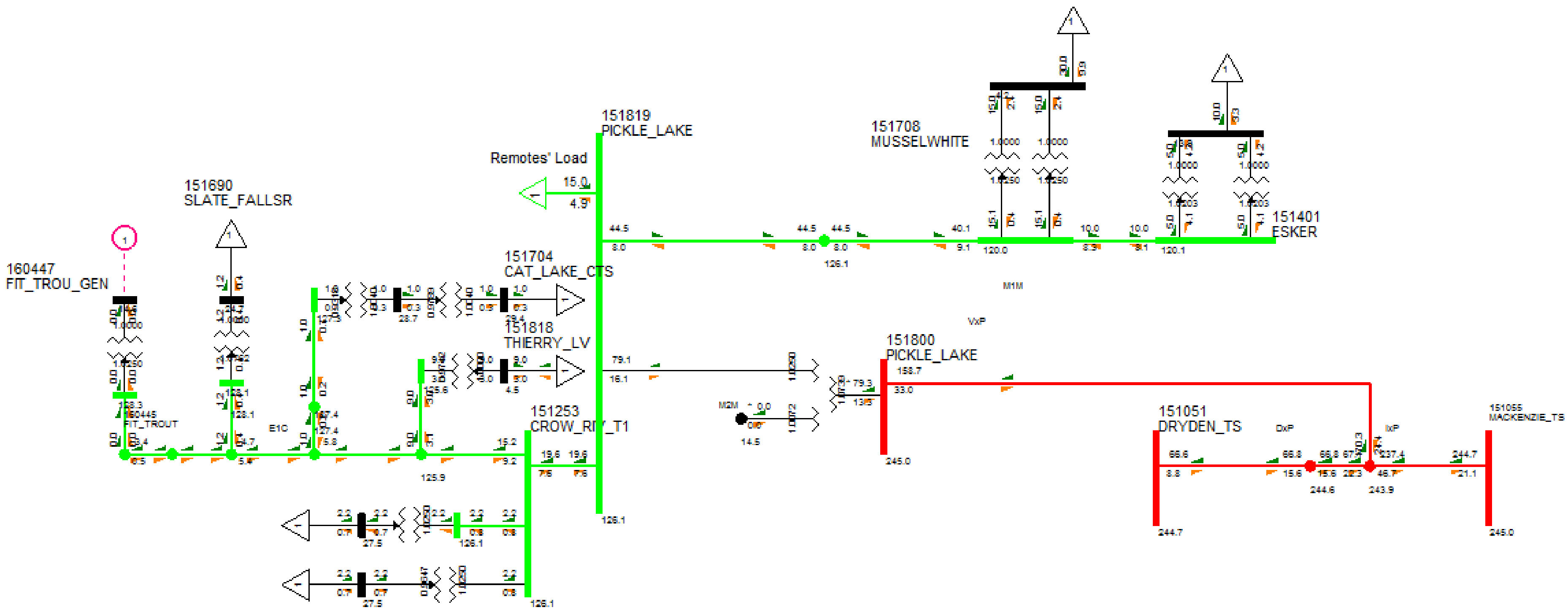
**Figure 21: 230 kV Line Option Pickle Lake Subsystem Configuration**

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### *Recommendation 2: Upgrade circuits E4D and E2R and supporting facilities*

The following table outlines the load meeting capability provided by the option and the long-term forecasted load.

**Table 61: Summary of Load Meeting Capability of Recommendation**

<table>
<tr><th>Recommendation</th><th>Incremental Capacity</th><th>Load Meeting Capability</th><th>Low Forecast Demand</th><th>Reference Forecast Demand</th><th>High Forecast Demand</th></tr>
<tr><td rowspan="2">Upgrade E4D and E2R<br>and<br>Transfer of Pickle Lake load to new line to Pickle Lake</td><td>34 MW</td><td>95 MW</td><td rowspan="2">100 MW</td><td rowspan="2">109 MW</td><td rowspan="2">136 MW</td></tr>
<tr><td>35 MW</td><td>130 MW</td></tr>
</table>

Table 62 outlines the cash flows used for the net present value economic analysis. Figure 22 and Figure 23 illustrate the single line diagram of the option and the power flow simulation for the reference scenario.

**Table 62: Summary of Cashflows for Upgrade to E4D and E2R**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line Cost** | 0.0 | 5.0 | | | | | | | | | | | | | | | | | | |
| **Station Cost** | 0.0 | 10.5 | | | | | | | | | | | | | | | | | | |
| **O&M** | 0.0 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| **Total Annual Cost** | 0.0 | 15.7 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| **Annual Amortized Cost** | 0.0 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| **Cumulative PV** | 0.0 | 0.8 | 1.6 | 2.4 | 3.2 | 3.9 | 4.6 | 5.2 | 5.9 | 6.5 | 7.1 | 7.7 | 8.2 | 8.7 | 9.2 | 9.7 | 10.2 | 10.6 | 11.1 | 11.5 |

**Figure 22: E4D and E2R Upgrade Diagram**

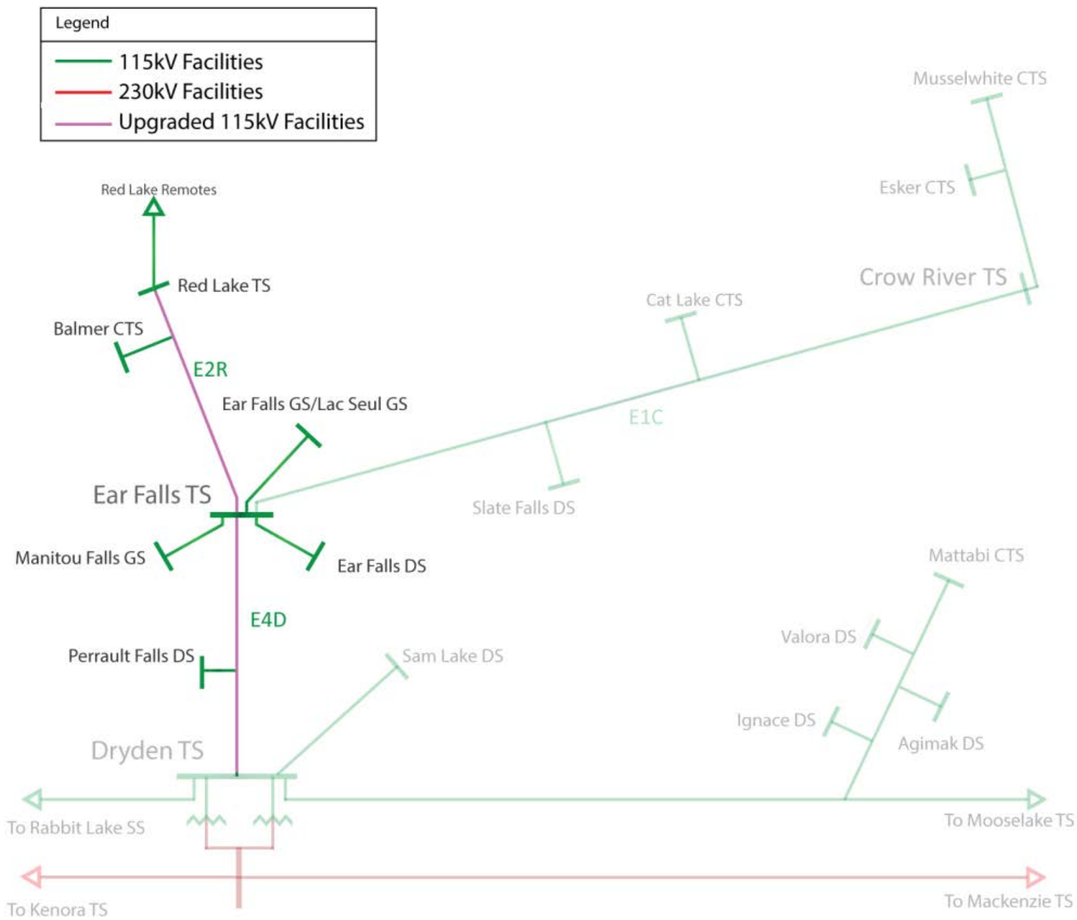
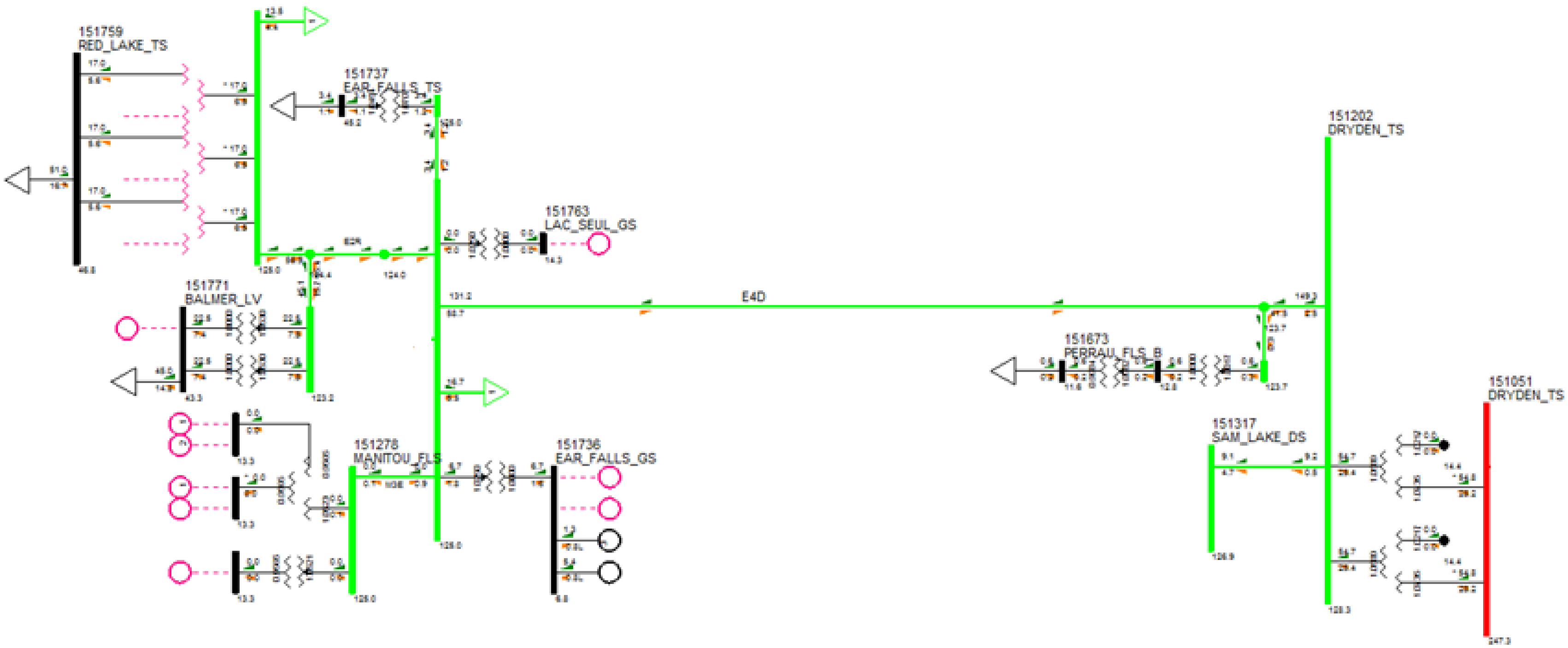


**Figure 23: E4D and E2R Upgrade Red Lake Subsystem Configuration**



*Recommendation 3: Manitou Falls condense operation during drought conditions*

In order to accommodate future growth in the Red Lake subsystem, new voltage control devices would need to be installed in the Ear Falls and Red Lake areas. New voltage control devices would be required in order to release the thermal capability provided to the Red Lake subsystem from the system upgrades being recommended.

OPG has informed the OPA that Manitou Falls units G1, G2, and G3 could be made to condense with minor maintenance work. Units G1, G2, and G3 would have a capability of approximately +/-14 MVar each, for a total of +/- 42 MVar. The OPA anticipates that the NPV cost associated with enabling and operating the condense features over the planning period is likely to be significantly less than the NPV cost of installing new voltage control devices.

## 10.7 Generation Options

For each of the three subsystems, at least one generation option was studied in detail. However, due to the different nature of each system, and thus the differing needs, each system was approached with a unique methodology to ensure that the generation option/s studied reflect the need of the subsystem.

The assumptions and methodologies used for developing the generation options are described below.

### 10.7.1 Pickle Lake Subsystem

*Assumptions*

The following assumptions were used to estimate the cost of CNG electricity generation in the Pickle Lake subsystem:

- Pickle Lake subsystem will remain connected to Ear Falls TS and 24 MW of load in the Pickle Lake subsystem will be served from Ear Falls TS

- Forecasted demand greater than 24 MW in the Pickle Lake subsystem (including remote communities in the Ring of Fire subsystem connecting at Pickle Lake) would be served by CNG fueled generation at Pickle Lake
- Generators will be dual fuel CNG/Diesel reciprocating engines. Engines will be capable of running predominantly on CNG, but can run on pure diesel as needed
- Generation would be fueled mainly by CNG, which would be compressed and transported from TCPL pipeline in the Ignace area via Highway 599
- Decanting stations would be required to decompress the natural gas for use
- CNG fuel delivery would be on a just in time basis due to challenges with large scale on-site CNG storage
- If CNG is unavailable generators will run on diesel, cost of supplying diesel and storage has not been included
- A sufficient number of trailers would be required to transport CNG as well as provide for some limited on-site storage to ensure a stable flow of fuel
- A Special Protection System triggered by the loss of more than one generator in the new facility, may be required to automatically shed load sufficient to maintain operation of E1C within appropriate limits
- Discrete generator unit sizes of 9.5 MW

### *Study Procedure*

To determine the feasibility and estimate the cost of implementing a CNG generation facility in the Pickle Lake subsystem, the following procedure was undertaken:

1. Load flow assessment in PSS/E (provided in this Section) was done to find the installed generation capacity at Pickle Lake that would be required to meet the peak forecast demand of the subsystem.
2. Using established transmission limits, hydroelectric generation profiles and load profiles for the subsystem, the capacity and energy that would need to be served by new CNG generation resources was estimated.
3. Using energy requirements estimate number of trucks and trailers (size of fleet) required to transport fuel based on a) trailer volume assumptions, b) fuel requirements and c) one day round trip;

4. Using generator capacity, number of trailers and annual energy requirements, capital, operations and maintenance, and fuel costs of the system were calculated.
5. These capital, operations and maintenance costs, were levelized over the project life and the present value over the planning period (2013-2033) was calculated.

### *Planning Level Assessment*

A summary of the technical capability of the generation options that were considered for the Pickle Lake subsystem is summarized below.

**Table 63: Summary of Capacity for Gas Generation at Pickle Lake**

| Option | Incremental Capacity | Load Meeting Capability | Low Forecast Demand | Reference Forecast Demand | High Forecast Demand |
|---|---|---|---|---|---|
| CNG Generation at Pickle Lake (38 MW) | 19 MW | 43 MW | 41 MW | 78 MW | 90 MW |
| CNG Generation at Pickle Lake (47.5 MW) | 23.5 MW | 47.5 MW | | | |
| CNG Generation at Pickle Lake (76 MW) | 57 MW | 81 MW | | | |
| CNG Generation at Pickle Lake (85.5 MW) | 66.5 MW | 90.5 MW | | | |

*Requires continued supply of 24 MW of load via E1C from Ear Falls

**Includes demand for Ring of Fire remote communities (7 MW)

The cost of supplying the growth needs of the Pickle Lake subsystem with CNG fueled generation are shown in Table 64 through Table 69. Figure 24 shows operation of the Pickle Lake subsystem with this option in the peak load case. Voltage profiles throughout the subsystem remain healthy in the general range of 118 kV to 125 kV. The installation of generation at Pickle Lake also provides some voltage control to the Pickle Lake subsystem.

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## Table 64: Summary of Cost for 38 MW of CNG Generation in Pickle Lake Subsystem

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 56.8 | 0.0 | 0.0 | 0.0 | 4.7 | 0.0 | 0.0 | 0.0 | 4.0 | 0.0 | 16.0 | 0.0 | 3.0 | 0.0 | 0.0 | 0.0 | 2.9 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 10.5 | 10.2 | 9.8 | 9.4 | 9.1 | 8.7 | 8.4 | 8.1 | 7.7 | 7.4 | 5.3 | 5.3 | 5.3 | 5.3 | 5.3 | 5.3 | 5.4 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 67.2 | 8.7 | 8.3 | 7.9 | 12.2 | 7.2 | 6.9 | 6.6 | 10.2 | 6.0 | 19.8 | 3.8 | 6.8 | 3.8 | 3.8 | 3.8 | 6.8 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 10.3 | 20.3 | 29.8 | 39.0 | 47.9 | 56.4 | 64.5 | 72.4 | 80.0 | 87.2 | 94.2 | 100.9 | 107.4 | 113.6 | 119.6 | 125.3 | 130.8 |

## Table 65: Summary of Cost for 47.5 MW of CNG Generation in Pickle Lake Subsystem

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 66.4 | 0.0 | 0.0 | 0.0 | 7.2 | 0.0 | 0.0 | 0.0 | 8.0 | 0.0 | 27.7 | 0.0 | 5.6 | 0.0 | 0.0 | 0.0 | 6.4 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 12.7 | 13.0 | 13.3 | 13.6 | 13.9 | 14.2 | 14.6 | 14.9 | 15.3 | 15.7 | 9.7 | 10.1 | 10.4 | 10.8 | 11.2 | 11.7 | 12.2 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 79.1 | 5.9 | 6.1 | 6.4 | 14.0 | 7.1 | 7.4 | 7.8 | 16.2 | 8.5 | 30.2 | 2.9 | 8.8 | 3.7 | 4.1 | 4.6 | 11.5 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 12.1 | 23.7 | 34.9 | 45.6 | 56.0 | 65.9 | 75.5 | 84.6 | 93.5 | 102.0 | 110.1 | 118.0 | 125.5 | 132.8 | 139.8 | 146.5 | 152.9 |

## Table 66: Summary of Cost for 76 MW of CNG Generation in Pickle Lake Subsystem

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 124.2 | 0.0 | 0.0 | 0.0 | 9.6 | 0.0 | 0.0 | 0.0 | 12.8 | 0.0 | 52.4 | 0.0 | 15.2 | 0.0 | 0.0 | 0.0 | 18.4 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 16.0 | 16.3 | 17.8 | 18.4 | 19.9 | 21.2 | 22.6 | 24.0 | 25.6 | 27.0 | 25.9 | 27.3 | 28.9 | 30.4 | 31.9 | 33.4 | 35.1 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 | -14.1 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 140.2 | 2.2 | 3.7 | 4.3 | 15.3 | 7.1 | 8.5 | 9.9 | 24.2 | 12.9 | 54.1 | 13.2 | 30.0 | 16.3 | 17.8 | 19.3 | 39.4 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 22.8 | 44.8 | 65.9 | 86.1 | 105.7 | 124.4 | 142.4 | 159.8 | 176.5 | 192.5 | 207.9 | 222.7 | 237.0 | 250.7 | 263.9 | 276.5 | 288.7 |

**Table 67: Summary of Cost for Compensation Associated with up to 76 MW of Gas Generation in Pickle Lake Subsystem**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | | | | | | | | | | | | | | | |
| Station cost | | | | 8.1 | | | | | | | | | | | | | | | | |
| O&M | | | | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 8.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Annual Amortized Cost | | | | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.4 | 0.8 | 1.2 | 1.5 | 1.9 | 2.2 | 2.5 | 2.8 | 3.1 | 3.4 | 3.7 | 4.0 | 4.2 | 4.5 | 4.7 | 4.9 | 5.1 |

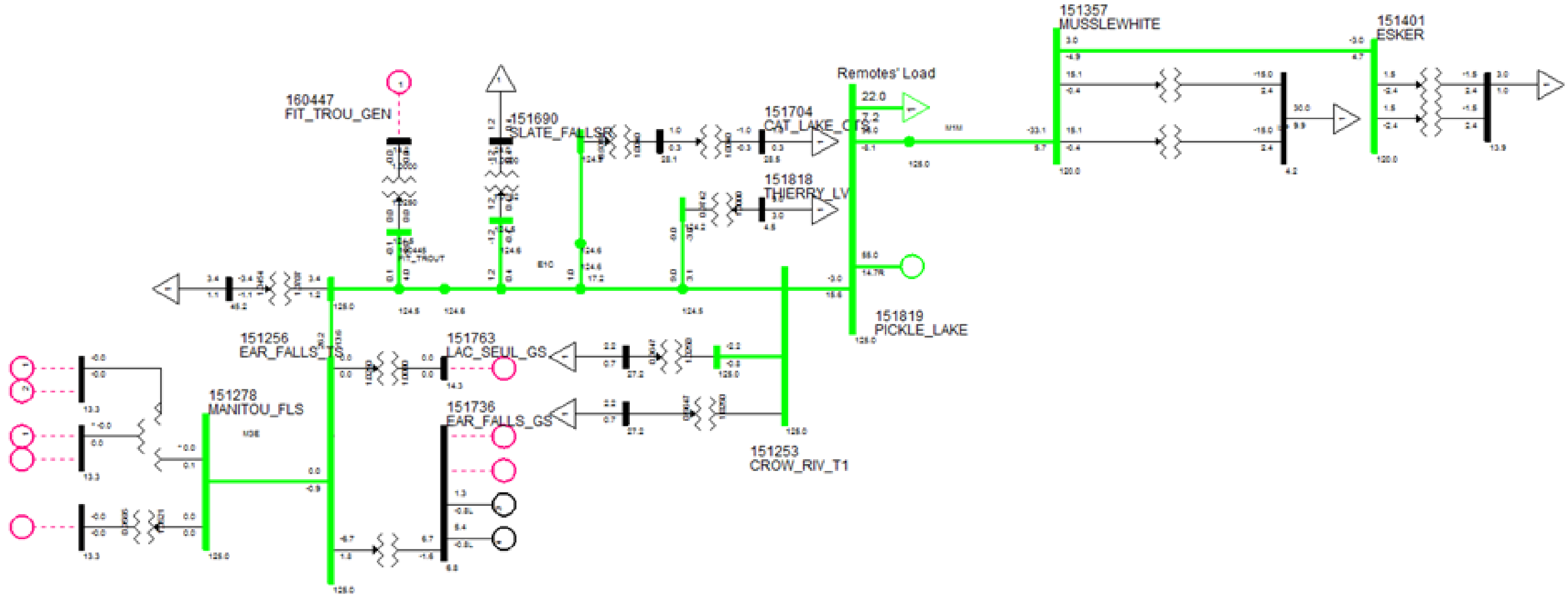
**Table 68: Summary of Cost for 85.5 MW of CNG Generation in Pickle Lake Subsystem**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 125.0 | 0.0 | 0.0 | 0.0 | 12.0 | 0.0 | 0.0 | 0.0 | 15.2 | 0.0 | 52.4 | 0.0 | 18.4 | 0.0 | 0.0 | 0.0 | 22.4 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 17.1 | 17.3 | 22.0 | 22.5 | 24.1 | 25.4 | 26.8 | 28.2 | 29.8 | 31.2 | 32.6 | 34.1 | 35.7 | 37.2 | 38.7 | 40.2 | 41.9 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 | -17.4 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 142.1 | 0.0 | 4.6 | 5.1 | 18.7 | 8.0 | 9.4 | 10.8 | 27.6 | 13.8 | 67.6 | 16.7 | 36.7 | 19.8 | 21.3 | 22.8 | 46.9 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 | 27.3 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 24.3 | 47.7 | 70.2 | 91.8 | 112.6 | 132.5 | 151.8 | 170.2 | 188.0 | 205.1 | 221.5 | 237.3 | 252.5 | 267.1 | 281.1 | 294.6 | 307.6 |

**Table 69: Summary of Cost for Compensation Associated with up to 85.5 MW of Gas Generation in Pickle Lake Subsystem**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | | | | | | | | | | | | | | | |
| Station cost | | | | 14.7 | | | | | | | | | | | | | | | | |
| O&M | | | | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 14.8 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Annual Amortized Cost | | | | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.7 | 1.4 | 2.1 | 2.8 | 3.4 | 4.0 | 4.6 | 5.2 | 5.7 | 6.2 | 6.7 | 7.2 | 7.7 | 8.1 | 8.5 | 8.9 | 9.3 |

**Figure 24: Generation Option Pickle Lake Subsystem Configuration**



### 10.7.2 **Red Lake Subsystem Generation Options**

#### *Assumptions*

The following assumptions were used to estimate the cost of natural gas electricity generation in the Red Lake subsystem:

- Natural gas would be supplied via the existing Union Gas pipeline in the Red Lake area for 30 MW generation (near-term) option;
- Natural gas would be supplied via the existing Union Gas pipeline in the Red Lake area and a new gas pipeline to future customer(s) for the 60 MW (long-term) option;
- Pipelines are assumed to be available and associated costs are not included in this analysis (except gas management charges). New pipeline capacity required for the second 30 MW of gas generation at Ear Falls is assumed to be linked to a future potential load customer, therefore if the incremental gas capacity is not developed neither will the load be present in the subsystem; and
- Discrete generator unit sizes of 9.5 MW.

#### *Study Procedure*

To estimate the cost of implementing natural gas generation in the Red Lake subsystem, the following procedure was taken:

1. Load flow assessment in PSS/E (provided in this Section) was done to find the installed generation capacity required to meet the need of the Red Lake subsystem;
2. Using established transmission limits, hydroelectric generation profiles and the identified need for the subsystem, determine the capacity and energy that new generation resources would need to served;
3. Using established unit costs, capital, operations and maintenance, and fuel costs of the new generation resources were calculated;
4. Using capacity size, gas management charges for a peaking facility in the area were estimated; and
5. These capital, operations and maintenance costs, were levelized over the project life and the present value over the planning period (2014-2033) was calculated.

### *Planning Assessment of Near-Term Option*

Table 70 summarizes the incremental capacity provided by this option as well as the total LMC of the Red Lake subsystem with this option, while Table 71 summarizes the cost of the option in the Red Lake subsystem.

**Table 70: Capacity and LMC Summary for Generation Options at Red Lake**

| Option | Incremental Capacity | Load Meeting Capability | Low Forecast Near-term Demand | Reference Forecast Near-term Demand | High Forecast Near-term Demand |
|---|---|---|---|---|---|
| NG Generation at Ear Falls (30 MW) | 30 MW | 91 MW | 91 MW | 91 MW | 91 MW |

Figure 25 illustrates the system state of the Red Lake subsystem with this option.

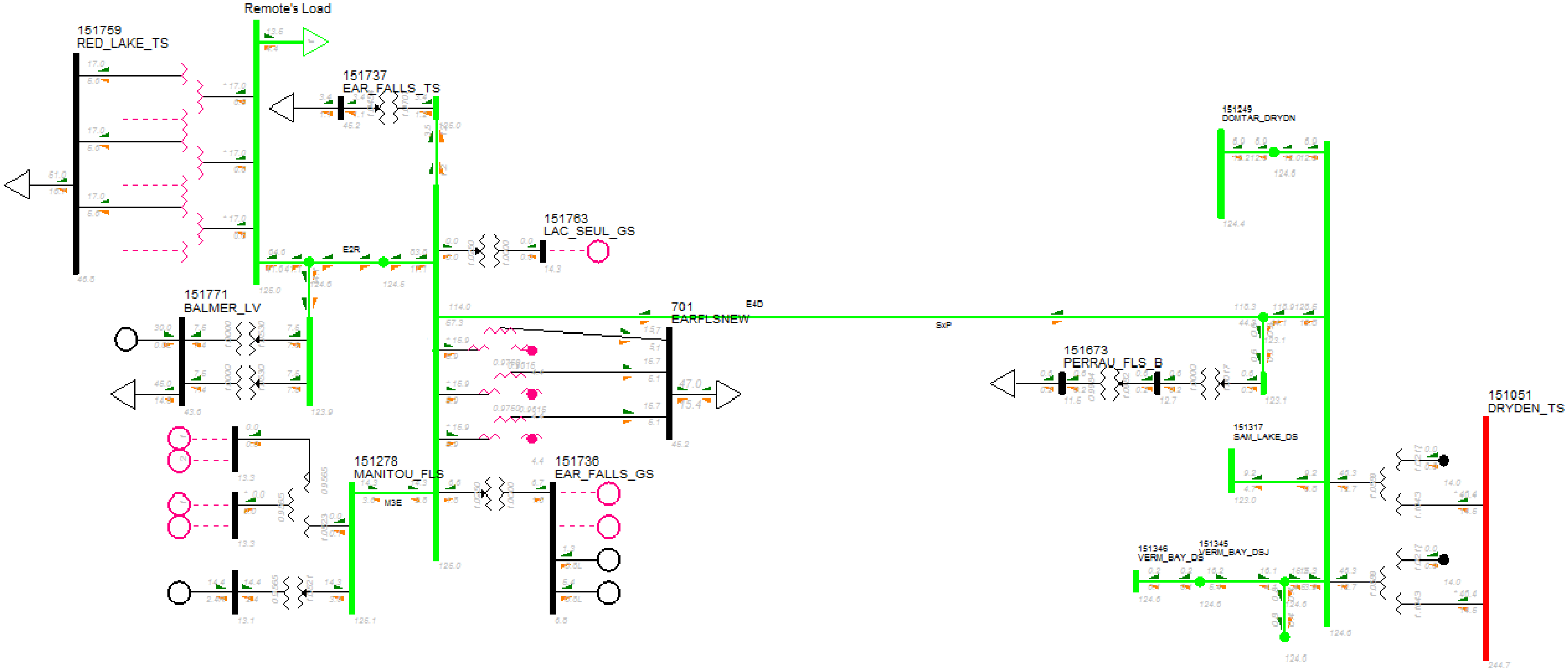
### Table 71: Summary of Cost for 30 MW of Gas Generation in Red Lake Subsystem in the Near Term

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gx Capital Cost | | 80.9 | | | | | | | | | | | | | | | | | | |
| Fixed O&M | | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Variable O&M | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Fuel Cost | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Avoided System Gen Cost | | 0.0 | 0.0 | 0.0 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 |
| Total Annual Gx Cost | | 82.7 | 1.8 | 1.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 | -0.8 |
| Levelized Annual Cost | 0.0 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 |
| Annual Amortized cost | 0.0 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 |
| Cumulative PV of Amortized cost | 0.0 | 5.3 | 10.3 | 15.2 | 17.7 | 20.1 | 22.4 | 24.6 | 26.8 | 28.8 | 30.8 | 32.7 | 34.5 | 36.2 | 37.9 | 39.5 | 41.1 | 42.6 | 44.0 | 45.4 |

### Table 72: Summary of Cost for Compensation Associated with 30 MW of Gas Generation in Red Lake Subsystem in the Near Term

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Station Cost | | 8.1 | | | | | | | | | | | | | | | | | | |
| O&M | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total Annual Cost | 0.0 | 8.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Annual Amortized Cost | 0.0 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Cumulative PV | 0.0 | 0.4 | 0.9 | 1.3 | 1.7 | 2.0 | 2.4 | 2.7 | 3.1 | 3.4 | 3.7 | 4.0 | 4.3 | 4.6 | 4.8 | 5.1 | 5.3 | 5.6 | 5.8 | 6.0 |

## Figure 25: 30 MW Generation Option Red Lake Subsystem Configuration

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Given the existing opportunity for 30 MW of gas generation at Red Lake, a second gas generator at Ear Falls could be sized to serve the remaining capacity needs of the Red Lake subsystem. With a total of 60 MW of gas generation in the Red Lake subsystem, the LMC of the subsystem would increase by 60 MW to 190 MW (assuming all Pickle Lake subsystem load on E1C is transferred to the new line to Pickle Lake). Table 73 summarizes the capacity provided by a single 30 MW facility at Red Lake as well as two facilities in the subsystem.

**Table 73: Summary of Incremental Capacity and LMC**

| Option | Incremental Capacity | Load Meeting Capability* | Low Forecast Long-term Demand | Reference Forecast Long-term Demand | High Forecast Long-term Demand |
|---|---|---|---|---|---|
| NG Generation at Ear Falls (30 MW) | 30 MW | 160 MW | 100 MW | 109 MW | 136 MW |
| NG Generation at Ear Falls (60 MW) | 60 MW | 190 MW | | | |

*Includes the capability of E4D and E2R after upgrading

Figure 25 and Figure 26, show the state of the Red Lake subsystem with each of these options implemented, while Table 74 to Table 77, provide a detailed summary of the costs for each option. The generators at Red Lake and/or Ear Falls help to maintain the voltages at those buses to a healthy range of 120 kV to 125 kV.

**Table 74: Summary of Cost for 30 MW of Gas Generation in Red Lake Subsystem in the Long Term**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gx Capital Cost | | | | | | | | | | | | | | | | | 80.9 | | | |
| Fixed O&M | | | | | | | | | | | | | | | | | 1.8 | 1.8 | 1.8 | 1.8 |
| Variable O&M | | | | | | | | | | | | | | | | | 0.0 | 0.0 | 0.0 | 0.0 |
| Fuel Cost | | | | | | | | | | | | | | | | | 0.0 | 0.0 | 0.0 | 0.0 |
| Avoided System Gen Cost | | | | | | | | | | | | | | | | | -2.7 | -2.7 | -2.7 | -2.7 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 80.1 | -0.9 | -0.9 | -0.9 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4.9 | 4.9 | 4.9 | 4.9 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.2 | 2.3 | 3.4 | 4.4 |

**Table 75: Summary of Cost for Compensation Associated with 30 MW of Gas Generation in Red Lake Subsystem in the Long Term**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Station Cost | | | | | | | | | | | | | | | | | 14.1 | | | |
| O&M | | | | | | | | | | | | | | | | | 0.1 | 0.1 | 0.1 | 0.1 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 14.2 | 0.1 | 0.1 | 0.1 |
| Annual Amortized Cost | | | | | | | | | | | | | | | | | 0.8 | 0.8 | 0.8 | 0.8 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 | 0.8 | 1.2 | 1.6 |

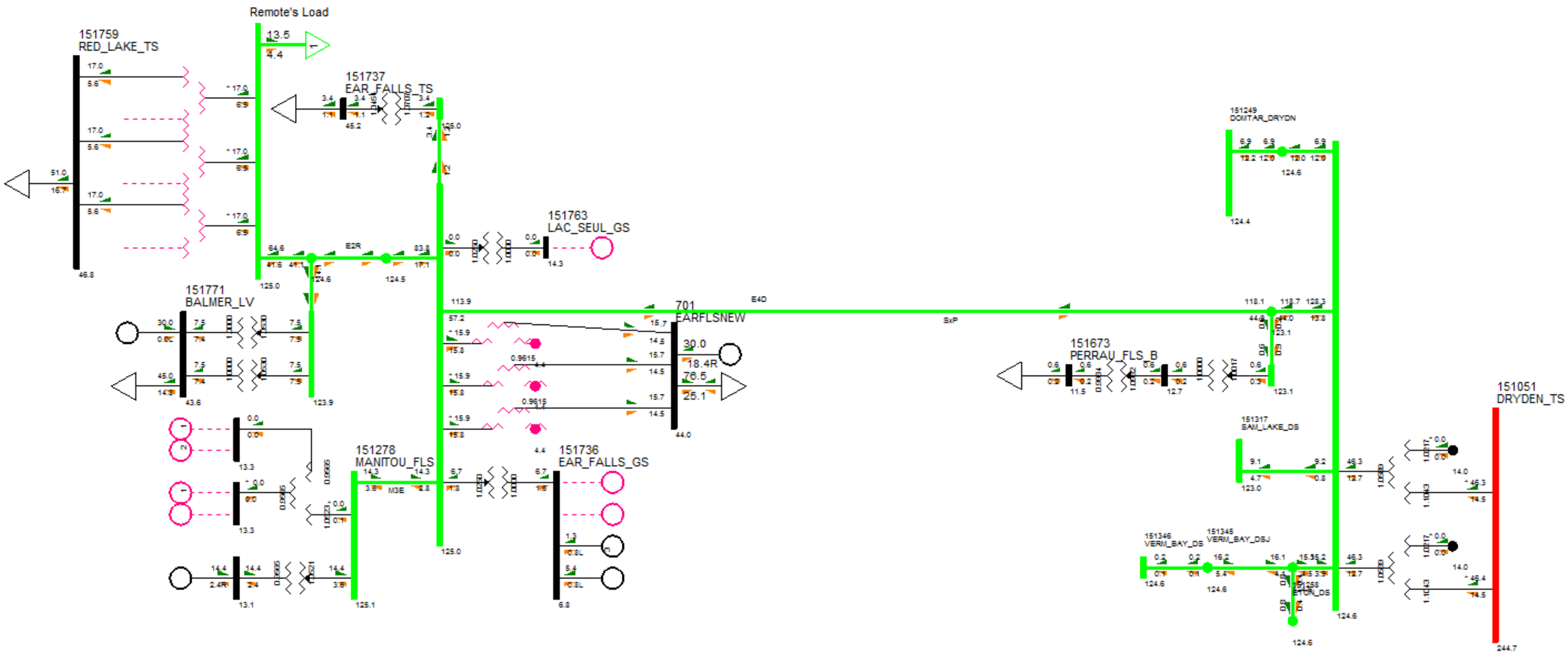
**Table 76: Summary of Cost for 60 MW of Gas Generation in Red Lake Subsystem in the Long Term**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gx Capital Cost | | | | | | | | | | | | | | | | | 145.7 | | | |
| Fixed O&M | | | | | | | | | | | | | | | | | 3.0 | 3.0 | 3.0 | 3.0 |
| Variable O&M | | | | | | | | | | | | | | | | | 0.0 | 0.0 | 0.0 | 0.0 |
| Fuel Cost | | | | | | | | | | | | | | | | | 0.0 | 0.0 | 0.0 | 0.0 |
| Avoided System Gen Cost | | | | | | | | | | | | | | | | | -4.9 | -4.9 | -4.9 | -4.9 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 143.8 | -1.9 | -1.9 | -1.9 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 8.4 | 8.4 | 8.4 | 8.4 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.9 | 3.7 | 5.5 | 7.2 |

### Table 77: Summary of Cost for Compensation Associated with 60 MW of Gas Generation in Red Lake Subsystem in the Long Term

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Station Cost | | | | | | | | | | | | | | | | | 6.9 | | | |
| O&M | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 7.0 | 0.1 | 0.1 | 0.1 |
| Annual Amortized Cost | | | | | | | | | | | | | | | | | 0.4 | 0.4 | 0.4 | 0.4 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 0.4 | 0.6 | 0.8 |

### Figure 26: 60 MW Generation Option Red Lake Subsystem Configuration

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### 10.7.3 Ring of Fire Subsystem Options

#### *Assumptions*

The following assumptions were made to determine the infrastructure required to implement diesel and CNG fueled generation at the mine-sites and its costs. Based on the infrastructure requirements, costs for capital, operating and maintenance and capital sustainment were estimated to determine the total cost of generating electricity at Ring of Fire mine-sites. For both fuel options, generators are assumed to not be connected to the Ontario electricity system.

Assumptions for CNG Fueled Mine-site Generation:

- Generators will be dual fuel CNG/Diesel reciprocating engines. Engines will be capable of running predominantly on CNG, but can run on pure diesel as needed;
- CNG would be compressed at a new compressor station in the Nakina area and transported on specialized high pressure transport trailers via the proposed road to the mine-sites;
- Decanting stations near the generators would be required to decompress the natural gas for use;
- CNG fuel delivery would be on a just in time basis due to challenges and additional cost of large scale on-site CNG storage;
- If CNG is unavailable generators will run on diesel;
- A sufficient number of trailers would be required to both transport fuel as well as provide for some limited on-site storage to ensure a stable flow of fuel; and
- Discrete generator unit sizes of 9.5 MW.

Assumptions for Diesel Fueled Mine-site Generation:

- Generators will be diesel fueled reciprocating engines;

- Diesel would be supplied from the Thunder Bay area and transported to the mine-sites via the proposed all-weather road, stored on site and used for in-mine equipment as well as for electricity generation;
- On-site diesel storage is available due to the variety of uses for diesel at the mine-sites, therefore timing and logistic challenges with fuel transport and delivery will not be as significant as for CNG; and
- Discrete generator unit sizes of 9.5 MW.

### *Study Procedure*

To estimate the cost of implementing a CNG or diesel electricity generation facility at the Ring of Fire mine-sites, the following procedure was undertaken:

1. Determine forecast peak load for the Ring of Fire mines based on the demand forecast;

2. Determine the required amount of generation capacity based on peak load;

3. Calculate the energy requirements (total kWh per year) by applying a estimated load factor to the peak load;

4. Calculate fuel required daily based on energy requirements;

5. Estimate number of trucks and trailers (size of fleet) required to transport fuel based on a) trailer volume assumptions, b) fuel requirements and c) one day round trip;

6. (CNG option only) Determine number of compressor and decanting stations based on amount of fuel required per day; and

7. Use the calculated values (generator capacity, number of trucks, annual fuel requirements, and decanting/compressing stations) to calculate initial capital costs, refurbishment costs, operation and maintenance costs, and fuel costs of the system.

8. These capital, operations and maintenance costs, were amortized over the project life and the present value over the planning period (2013-2033) was calculated.

### *Planning Level Assessment*

The generation options considered for supplying the Ring of Fire subsystem would only supply the mining load. The five remote communities in the Ring of Fire subsystem have been determined to be economic to connect as per the findings of the Remote Community Connection Plan. Backup generation capacity is considered to use consistent reliability criteria specified under ORTAC. Table 78 outlines the generation solution options considered for the Ring of Fire subsystem mining demand.

**Table 78: Summary of Incremental Capacity and LMC**

| Option | Incremental Capacity | Load Meeting Capability for Mining | Low Forecast Long-term Mining Demand | Reference Forecast Long-term Mining Demand | High Forecast Long-term Mining Demand |
|---|---|---|---|---|---|
| 38 MW of CNG | 22 MW | 22 MW | 0 MW | 22 MW | 66 MW |
| 38 MW of Diesel | 22 MW | 22 MW | | | |
| 57 MW of CNG | 44 MW | 44 MW | | | |
| 57 MW of Diesel | 44 MW | 44 MW | | | |
| 85.5 MW of CNG | 71 MW | 71 MW | | | |
| 85.5 MW of Diesel | 71 MW | 71 MW | | | |

Table 79 through Table 83 below summarize the cost profiles for each option.

## Table 79: Summary of Cost for 38 MW Diesel Option for Ring of Fire

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 39.8 | 0.0 | 0.0 | 0.0 | 1.8 | 0.0 | 0.0 | 0.0 | 1.8 | 0.0 | 24.7 | 0.0 | 1.8 | 0.0 | 0.0 | 0.0 | 1.8 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 31.6 | 32.1 | 32.6 | 33.1 | 33.7 | 34.2 | 34.8 | 35.4 | 36.0 | 44.5 | 45.2 | 45.9 | 46.7 | 47.4 | 48.1 | 48.8 | 49.6 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 71.4 | 23.8 | 24.3 | 24.8 | 27.1 | 25.9 | 26.5 | 27.0 | 29.5 | 36.1 | 61.5 | 37.6 | 40.1 | 39.1 | 39.8 | 40.4 | 43.1 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 31.1 | 61.0 | 89.7 | 117.3 | 143.9 | 169.5 | 194.0 | 217.7 | 240.4 | 262.2 | 283.2 | 303.4 | 322.8 | 341.5 | 359.4 | 376.7 | 393.3 |

## Table 80: Summary of Cost for 57 MW Diesel Option for Ring of Fire

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 58.8 | 0.0 | 0.0 | 0.0 | 3.0 | 0.0 | 0.0 | 0.0 | 3.0 | 0.0 | 37.1 | 0.0 | 3.6 | 0.0 | 0.0 | 0.0 | 3.6 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 32.2 | 32.7 | 33.2 | 72.7 | 74.0 | 75.2 | 76.5 | 77.8 | 79.2 | 88.4 | 89.8 | 91.2 | 92.7 | 94.3 | 95.6 | 97.0 | 98.6 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 91.0 | 15.9 | 16.4 | 55.9 | 60.2 | 58.4 | 59.7 | 61.0 | 65.4 | 71.6 | 110.0 | 74.4 | 79.5 | 77.5 | 78.8 | 80.2 | 85.4 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 53.1 | 104.1 | 153.2 | 200.4 | 245.8 | 289.4 | 331.4 | 371.7 | 410.5 | 447.8 | 483.7 | 518.1 | 551.3 | 583.2 | 613.8 | 643.3 | 671.7 |

## Table 81: Summary of Cost for 85.5 MW Diesel Option for Ring of Fire

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 87.3 | 0.0 | 0.0 | 0.0 | 4.8 | 0.0 | 0.0 | 0.0 | 4.8 | 0.0 | 55.6 | 0.0 | 5.4 | 0.0 | 0.0 | 0.0 | 5.4 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 33.1 | 33.5 | 34.1 | 112.6 | 114.6 | 116.5 | 118.5 | 120.5 | 122.7 | 132.6 | 134.7 | 136.8 | 139.1 | 141.5 | 143.5 | 145.5 | 148.0 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 120.4 | 6.5 | 7.1 | 85.6 | 92.4 | 89.5 | 91.5 | 93.5 | 100.5 | 105.6 | 163.3 | 109.8 | 117.5 | 114.5 | 116.5 | 118.5 | 126.4 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 | 84.1 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 74.8 | 146.7 | 215.9 | 282.3 | 346.3 | 407.7 | 466.9 | 523.7 | 578.3 | 630.9 | 681.4 | 730.0 | 776.7 | 821.6 | 864.8 | 906.3 | 946.3 |

## Table 82: Summary of Cost for 38 MW CNG Option for Ring of Fire

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 65.0 | 0.0 | 0.0 | 0.0 | 8.0 | 0.0 | 0.0 | 0.0 | 8.0 | 0.0 | 24.7 | 0.0 | 10.4 | 0.0 | 0.0 | 0.0 | 10.4 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 | 18.7 | 18.7 | 18.7 | 18.9 | 18.9 | 18.9 | 18.9 | 18.9 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 | -8.3 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 80.7 | 7.4 | 7.4 | 7.4 | 15.4 | 7.4 | 7.4 | 7.4 | 15.4 | 10.4 | 35.1 | 10.4 | 20.9 | 10.5 | 10.5 | 10.5 | 20.9 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 16.5 | 32.4 | 47.7 | 62.4 | 76.6 | 90.2 | 103.2 | 115.8 | 127.9 | 139.5 | 150.7 | 161.4 | 171.7 | 181.7 | 191.2 | 200.4 | 209.2 |

## Table 83: Summary of Cost for 57 MW CNG Option for Ring of Fire

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 93.5 | 0.0 | 0.0 | 0.0 | 18.4 | 0.0 | 0.0 | 0.0 | 18.4 | 0.0 | 37.1 | 0.0 | 20.0 | 0.0 | 0.0 | 0.0 | 20.0 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 16.6 | 16.6 | 16.6 | 33.2 | 33.7 | 33.7 | 33.7 | 33.7 | 33.7 | 36.7 | 36.7 | 36.7 | 36.8 | 36.8 | 36.8 | 36.8 | 36.8 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 110.1 | -0.2 | -0.2 | 16.4 | 35.3 | 16.9 | 16.9 | 16.9 | 35.3 | 19.9 | 57.0 | 19.9 | 40.0 | 20.0 | 20.0 | 20.0 | 40.0 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 | 27.9 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 24.8 | 48.6 | 71.6 | 93.6 | 114.8 | 135.2 | 154.8 | 173.6 | 191.7 | 209.1 | 225.9 | 242.0 | 257.5 | 272.4 | 286.7 | 300.4 | 313.7 |

## Table 84: Summary of Cost for 85.5 MW CNG Option for Ring of Fire

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Cost | 0.0 | 0.0 | 0.0 | 136.3 | 0.0 | 0.0 | 0.0 | 28.0 | 0.0 | 0.0 | 0.0 | 28.0 | 0.0 | 55.6 | 0.0 | 29.6 | 0.0 | 0.0 | 0.0 | 29.6 |
| O&M and Fuel | 0.0 | 0.0 | 0.0 | 17.9 | 17.9 | 17.9 | 51.1 | 52.1 | 52.1 | 52.1 | 52.1 | 52.1 | 55.1 | 55.1 | 55.1 | 55.2 | 55.2 | 55.2 | 55.2 | 55.2 |
| System Gen Credit | 0.0 | 0.0 | 0.0 | 0.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 | -27.0 |
| Total Annual Gx Cost | 0.0 | 0.0 | 0.0 | 154.1 | -9.1 | -9.1 | 24.1 | 53.1 | 25.1 | 25.1 | 25.1 | 53.1 | 28.1 | 83.7 | 28.1 | 57.8 | 28.2 | 28.2 | 28.2 | 57.8 |
| Annual Amortized cost | 0.0 | 0.0 | 0.0 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 | 37.1 |
| Cumulative PV of Amortized cost | 0.0 | 0.0 | 0.0 | 33.0 | 64.7 | 95.2 | 124.6 | 152.8 | 179.9 | 206.0 | 231.1 | 255.2 | 278.3 | 300.6 | 322.1 | 342.7 | 362.5 | 381.6 | 399.9 | 417.5 |

## 10.8 Transmission Options

### *Assumptions*

In determining the cost of transmission options, the following were assumed:

- Unit cost estimates for new facilities were provided by a study conducted for the OPA by SNC Lavalin T&D. The report has been included in Section 11.3;
- Operations and maintenance costs were estimated as a percentage of the capital cost of the project, and would be incurred every year from the in-service date to the end of the projects useful life;
- Land cost was not included. Land costs are difficult to determine given the types of land and the variety of land holders that certain options described in this report may occupy; and
- Impact Benefit Agreements that may be negotiated between future projects proponents and impacted First Nations have not been estimated or included in the costs of options.

### *Procedure*

To estimate the cost of transmission options to supply the North of Dryden sub-region, the following procedure was taken:

1. Load flow assessment in PSS/E (provided in this Section) was done to determine the capability of each option and the amount of capability of voltage control devices required to achieve the LMC;
2. Using unit costs for lines and stations, line lengths, number and types of new stations and/or station upgrades and voltage control requirements, capital, operations and maintenance costs of the system were calculated;
3. The amount of system generation that could be displaced after 2018, by associated local generation options for the subsystem was calculated; and
4. These capital, operations and maintenance costs and attributed costs for incremental system generation beginning in 2018, were levelized over the project life and the present value over the planning period (2013-2033) was calculated.

### 10.8.1 **Red Lake Subsystem Transmission Options**

#### *Near-term Option - Upgrade of E4D and E2R*

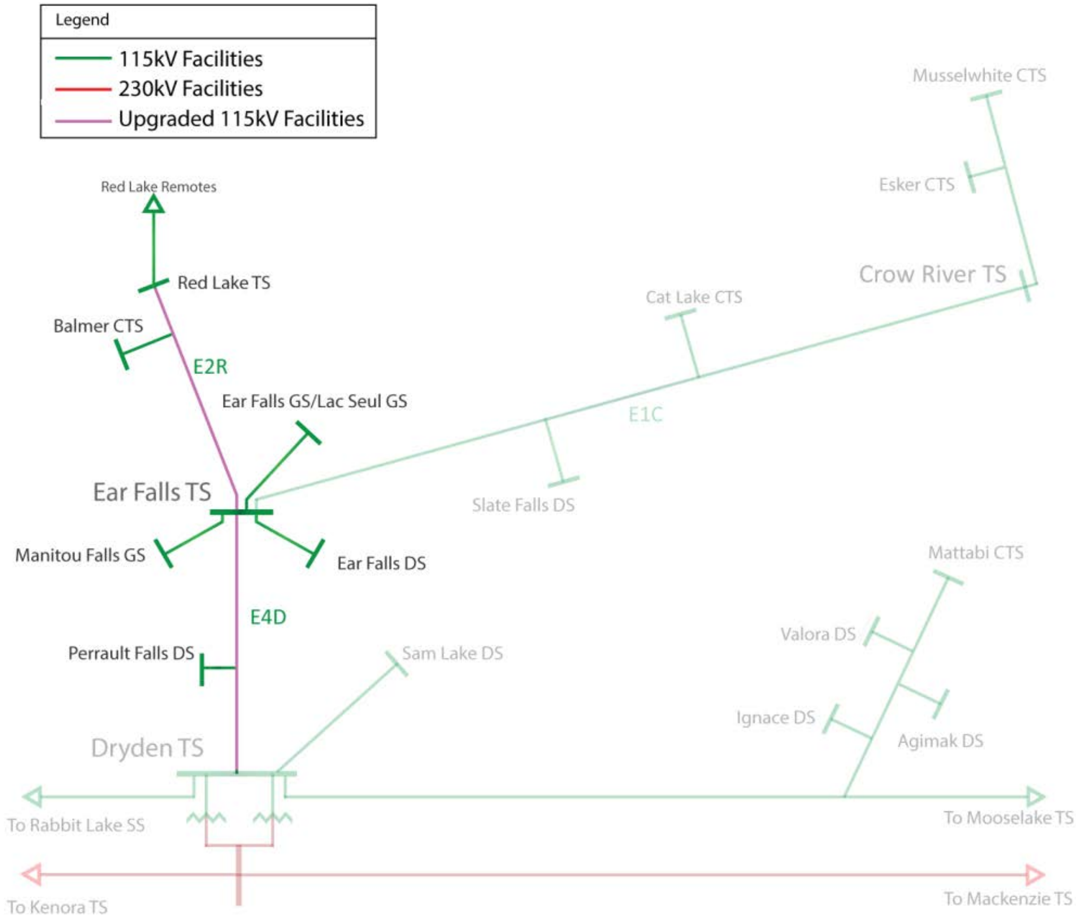
The existing lines serving the Red Lake subsystem are E4D, from Dryden to Ear Falls, and E2R, from Ear Falls to Red Lake. E4D has a thermal rating of 470 amps, and a transfer capability of 100 MVA (at 125 kV nominal voltage), while E2R a thermal rating of 420 amps, and a transfer capability of 91 MVA (125 kV nominal voltage). Based on dependable hydroelectric generation at Manitou Falls GS, Ear Falls GS and Lac Seul GS, and the current summer transmission line ratings, 85 MW of load can be served from Ear Falls TS. The Red Lake subsystem has an LMC of 61 MW, while the Pickle Lake subsystem has an LMC of 24 MW.

Hydro One has identified that E4D can be upgraded to a thermal rating of 670 amps, while E2R can be upgraded to 620 amps. After these line upgrades and the installation of an appropriate amount of voltage control at Ear Falls TS the Red Lake subsystem LMC will rise to 95 MW, assuming the Pickle Lake subsystem continues to be supplied solely from Ear Falls via circuit E1C and the LMC remains at 24 MW. A diagram of the upgrade of E4D and E2R is provided in Figure 27.

**Table 85: Summary of Load Meeting Capability**

| Option | Incremental Capacity | Load Meeting Capability | Low Forecast Demand | Reference Forecast Demand | High Forecast Demand |
|---|---|---|---|---|---|
| Upgrade E4D and E2R | 34 MW | 95 MW | 100 MW | 109 MW | 136 MW |
| and Transfer of Pickle Lake load to new line to Pickle Lake | 35 MW | 130 MW | | | |

**Figure 27: E4D and E2R Upgrade Diagram**

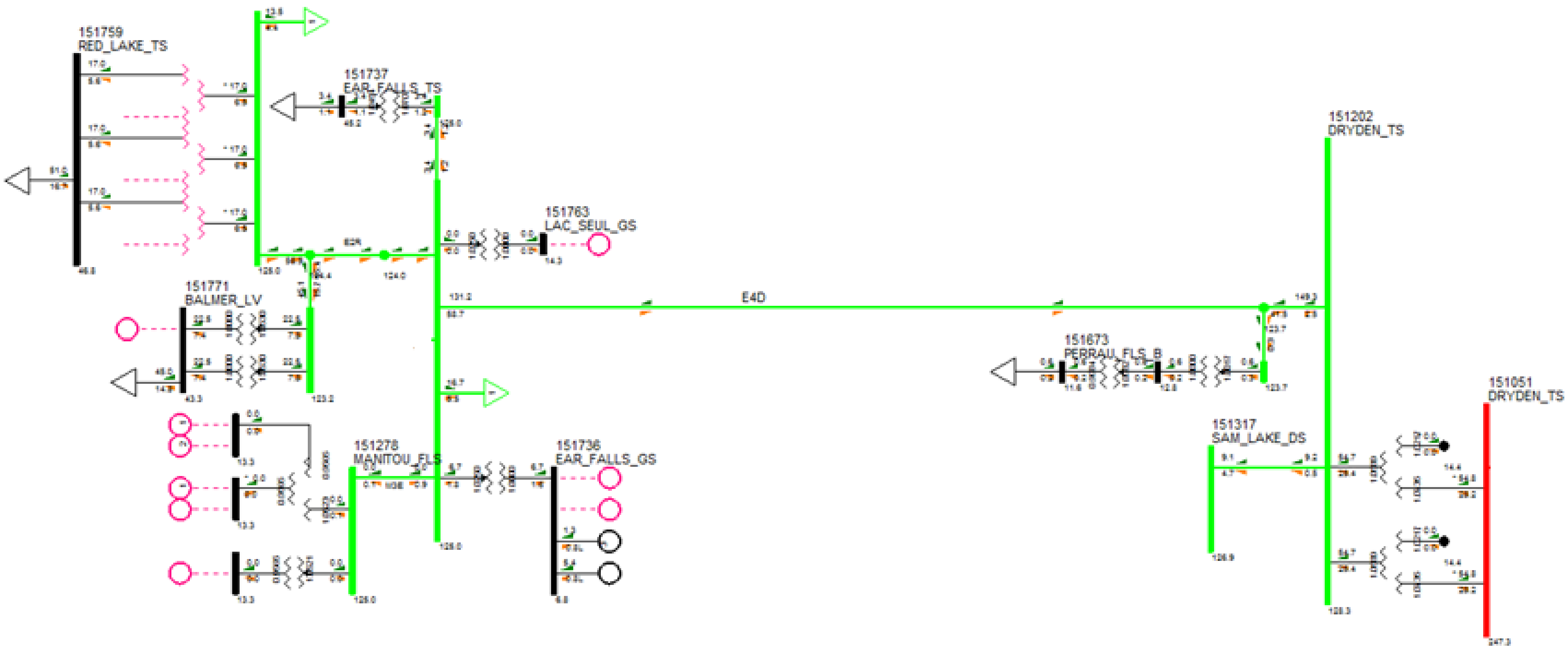



Hydro One has indicated that upgrading these lines as well as the installation of required voltage control devices could be completed within the near-term period. Table 86 below shows the cost breakdown of the upgrade option which includes the required voltage control devices. Figure 28 shows the load flow case during peak load. Ear Falls TS and Red Lake TS voltage is maintained in a healthy range of 120 kV to 125 kV.

### Table 86: E4D and E2R Upgrade Cost Summary

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line Cost | 0.0 | 5.0 | | | | | | | | | | | | | | | | | | |
| Station Cost | 0.0 | 10.5 | | | | | | | | | | | | | | | | | | |
| O&M | 0.0 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Total Annual Cost | 0.0 | 15.7 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Annual Amortized Cost | 0.0 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| Cumulative PV | 0.0 | 0.8 | 1.6 | 2.4 | 3.2 | 3.9 | 4.6 | 5.2 | 5.9 | 6.5 | 7.1 | 7.7 | 8.2 | 8.7 | 9.2 | 9.7 | 10.2 | 10.6 | 11.1 | 11.5 |

### Figure 28: E4D and E2R Upgrade Red Lake Subsystem Configuration



### *Medium- and Long-term Option - 115 kV Line from Dryden TS to Ear Falls TS*

This option is to build a new 115 kV single circuit line connecting at Dryden TS running to Ear Falls TS. A diagram of this option is provided in Figure 29. Because there are two local generation options for the Red Lake subsystem (30 MW, 60 MW), the 115 kV transmission option has been developed for an LMC of 160 MW and 190 MW. The option designed to have an LMC of 160 MW is comparable to the capability of the 30 MW Red Lake generation option and 190 MW LMC option is comparable to the 60 MW gas generation option, which meets the needs of the high scenario demand forecast. This difference in transmission LMC is determined by the voltage control requirements at Ear Falls TS.

**Table 87: Summary of Load Meeting Capability**

| Option | Incremental Capacity | Load Meeting Capability | Low Forecast Demand | Reference Forecast Demand | High Forecast Demand |
|---|---|---|---|---|---|
| New 115 kV line from Dryden to Ear Falls with less compensation (160 MW) | 30 MW | 160 MW | 100 MW | 109 MW | 136 MW |
| New 115 kV line from Dryden to Ear Falls with more compensation (190 MW) | 60 MW | 190 MW | | | |

**Figure 29: New 115 kV line to Ear Falls Diagram**

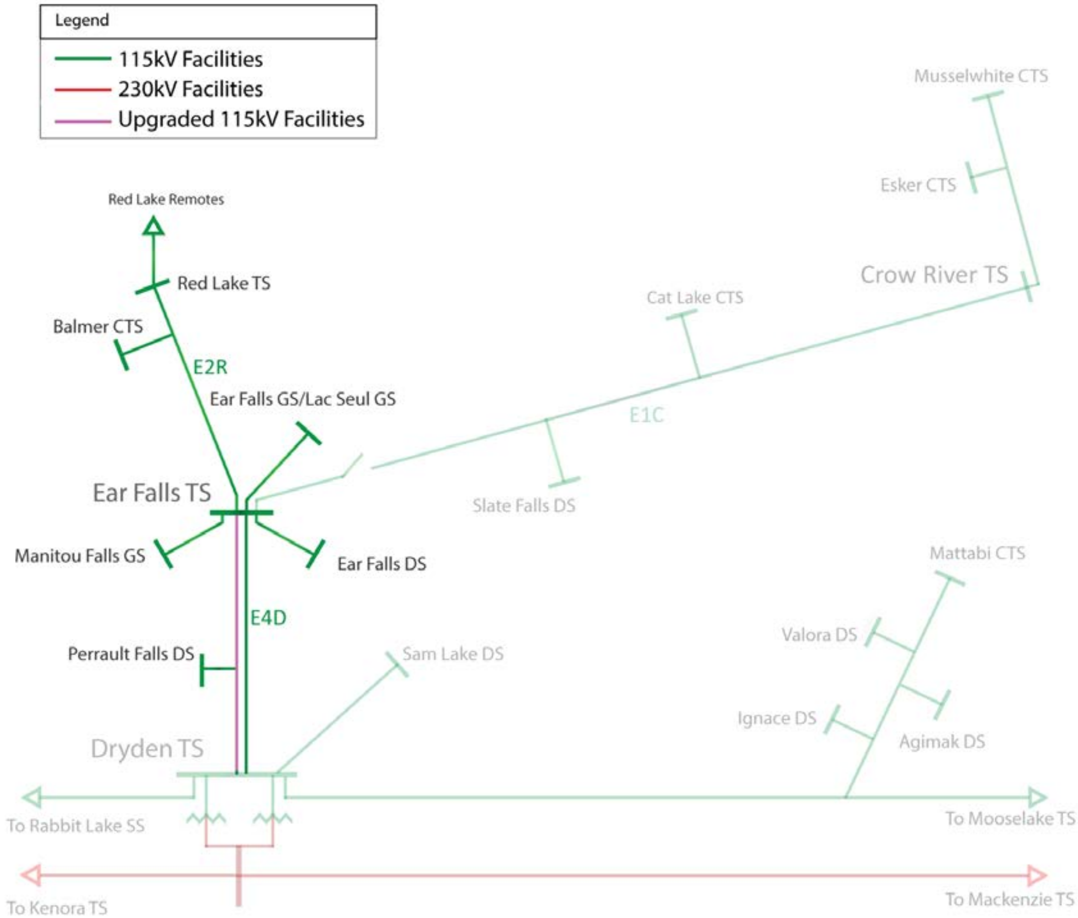



Figure 30, shows the peak load flow case for this option. Voltage at Ear Falls TS is maintained within a healthy range of 120 kV to 125 kV.

Table 88 and Table 89 summarize the annual cashflows and cumulative NPV cost for the options.

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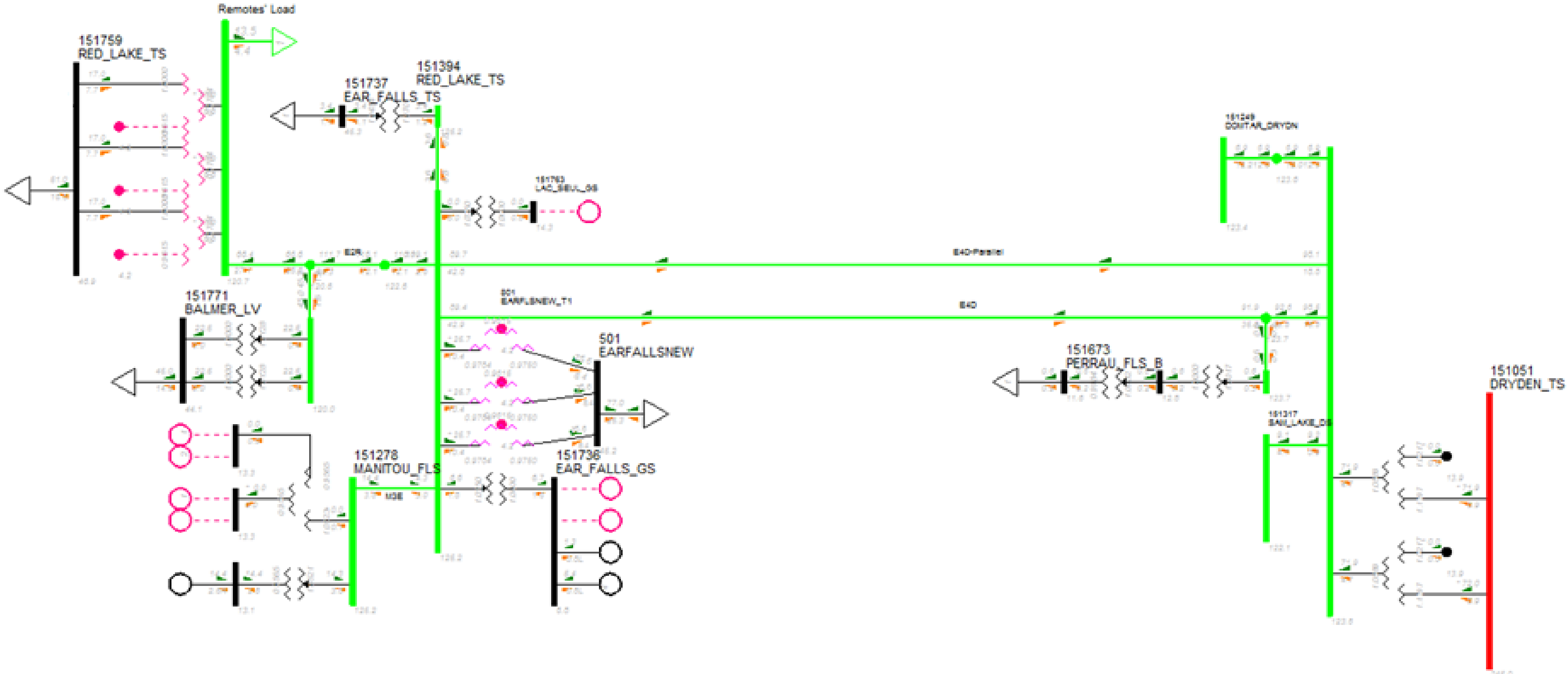
## Table 88: 115 kV line to Ear Falls 160 MW LMC Cost Summary

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | | | | | | | | | | | | 45.3 | | | |
| Station cost | | | | | | | | | | | | | | | | | 45.6 | | | |
| O&M | | | | | | | | | | | | | | | | | 0.9 | 0.9 | 0.9 | 0.9 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 91.8 | 0.9 | 0.9 | 0.9 |
| Annual Amortized Cost | | | | | | | | | | | | | | | | | 5.1 | 5.1 | 5.1 | 5.1 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.7 | 5.4 | 7.9 | 10.3 |

## Table 89: 115 kV line to Ear Falls 190 MW LMC Cost Summary

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | | | | | | | | | | | | 45.3 | | | |
| Station cost | | | | | | | | | | | | | | | | | 62.4 | | | |
| O&M | | | | | | | | | | | | | | | | | 1.1 | 1.1 | 1.1 | 1.1 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 108.7 | 1.1 | 1.1 | 1.1 |
| Annual Amortized Cost | | | | | | | | | | | | | | | | | 6.1 | 6.1 | 6.1 | 6.1 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.2 | 6.4 | 9.4 | 12.2 |

**Figure 30: 115 kV Line Option Red Lake Subsystem Configuration**

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### 10.8.2 Pickle Lake Subsystem Transmission Options

The transmission options for the Pickle Lake subsystem include:

1. A new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker on the tap line and terminating at Crow River DS in Pickle Lake;

2. A new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker on the tap line and running to Pickle Lake terminating at Crow River DS or a new TS in the Pickle Lake area with a new 230/115 kV autotransformer at Crow River DS or a new station; and

3. A new single circuit line pre-built to 230 kV standards (230 kV structures, and hardware) and connecting it to M2D on the 115 kV system east of Dryden with an in-line breaker on the tap line. When additional capacity is required the line would be reterminated on the 230 kV system near Dryden (D26A) and a 230/115 kV autotransformer would be installed at Crow River DS or a new station in Pickle Lake.

For all of these transmission options, it is assumed that following the installation of a new line to Pickle Lake, the line E1C, connecting Ear Falls TS to Crow River DS (at Pickle Lake), would be normally open at Ear Falls. As a result, all customers in the Pickle Lake subsystem would be normally supplied by the new line to Pickle Lake. During sustained outages of the new line to Pickle Lake, some load in the Pickle Lake subsystem may be able to be restored by closing the normally E1C at Ear Falls TS and serving load in the Pickle Lake subsystem from Ear Falls TS. The amount of load that can be restored in the Pickle Lake subsystem from Ear Falls TS will be limited by the available capacity of circuits E4D and E1C.

### *115 kV Line to Pickle Lake*

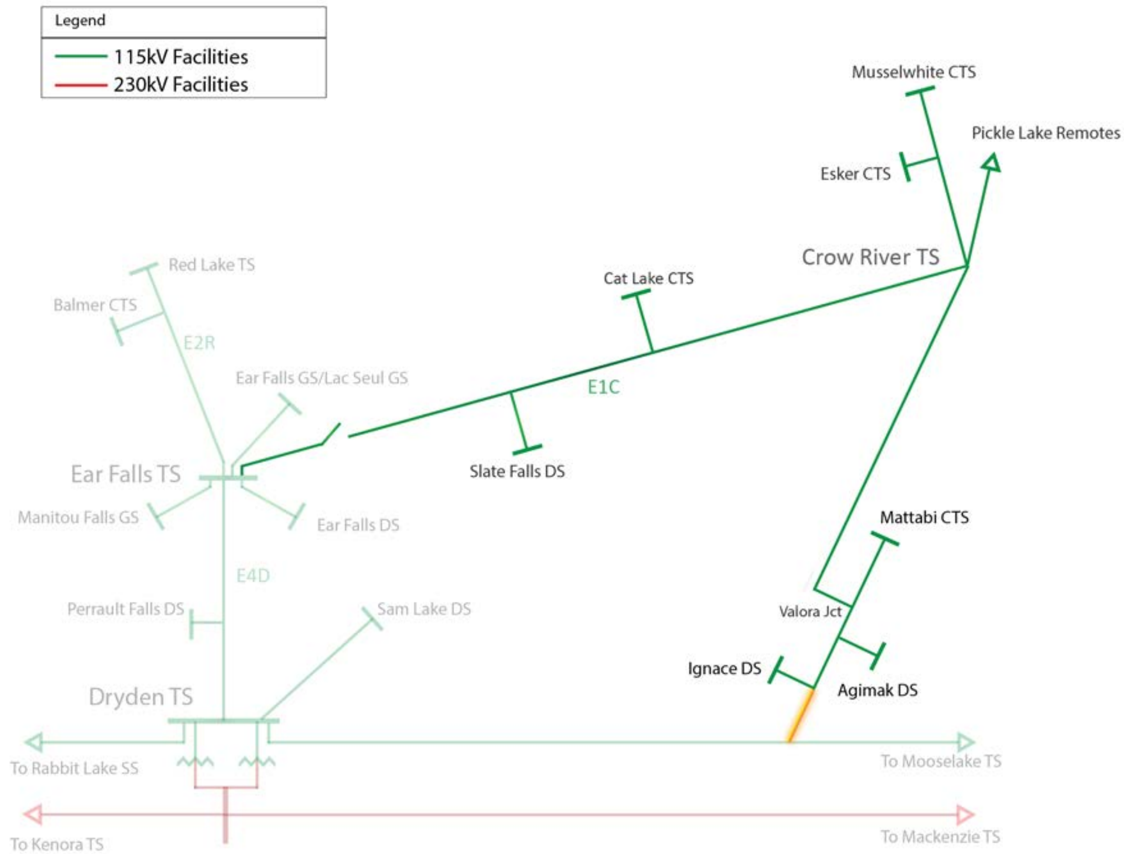
This option is to install a new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker and terminating at Crow River DS in Pickle Lake. Currently, there are a number of short sections of 29M1 between Ignace and Valora which have thermal ratings which are lower than the rest of the line. These sections will need to be upgraded to a thermal rating of at least 500 amps to allow the new line to Pickle Lake to have the required transfer capability.

**Table 90: Summary of Load Meeting Capability**

| Option | Incremental Capacity | Load Meeting Capability | Low Forecast Demand | Reference Forecast Demand | High Forecast Demand |
|---|---|---|---|---|---|
| New 115 kV line from Valora to Pickle Lake | 46 MW | 70 MW | 48 MW | 78 MW (100 MW) | 90 MW (156 MW) |

Figure 31 shows the Pickle Lake subsystem with this option, highlighting the section of 29M1 that would require upgrading.

**Figure 31: New 115 kV line to Pickle Lake Diagram**




A summary of the cost for this option can be found in Table 91 below.

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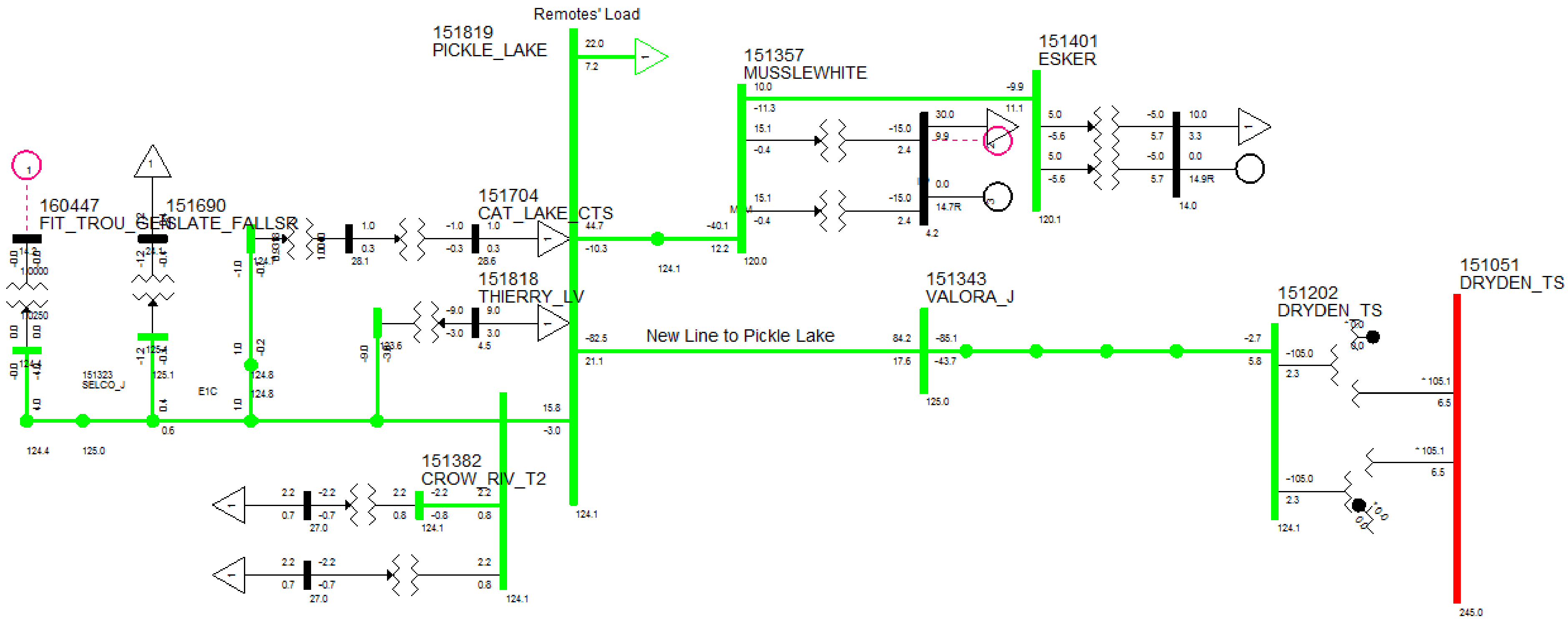
Figure 32 shows the load flow case during peak load. The Pickle Lake bus voltage is maintained in a healthy range of 120 kV to 125 kV.

**Table 91: 115 kV line to Pickle Lake Cost Summary**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | 104 | | | | | | | | | | | | | | | | |
| Station cost | | | | 22.5 | | | | | | | | | | | | | | | | |
| O&M | | | | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 127.9 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 |
| Annual Amortized Cost | | | | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 | 7.1 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 6.4 | 12.5 | 18.3 | 24.0 | 29.4 | 34.6 | 39.7 | 44.5 | 49.1 | 53.6 | 57.9 | 62.0 | 66.0 | 69.8 | 73.5 | 77.0 | 80.4 |

**Figure 32: 115 kV Line Option Pickle Lake Subsystem Configuration**

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### *230 kV Line to Pickle Lake*

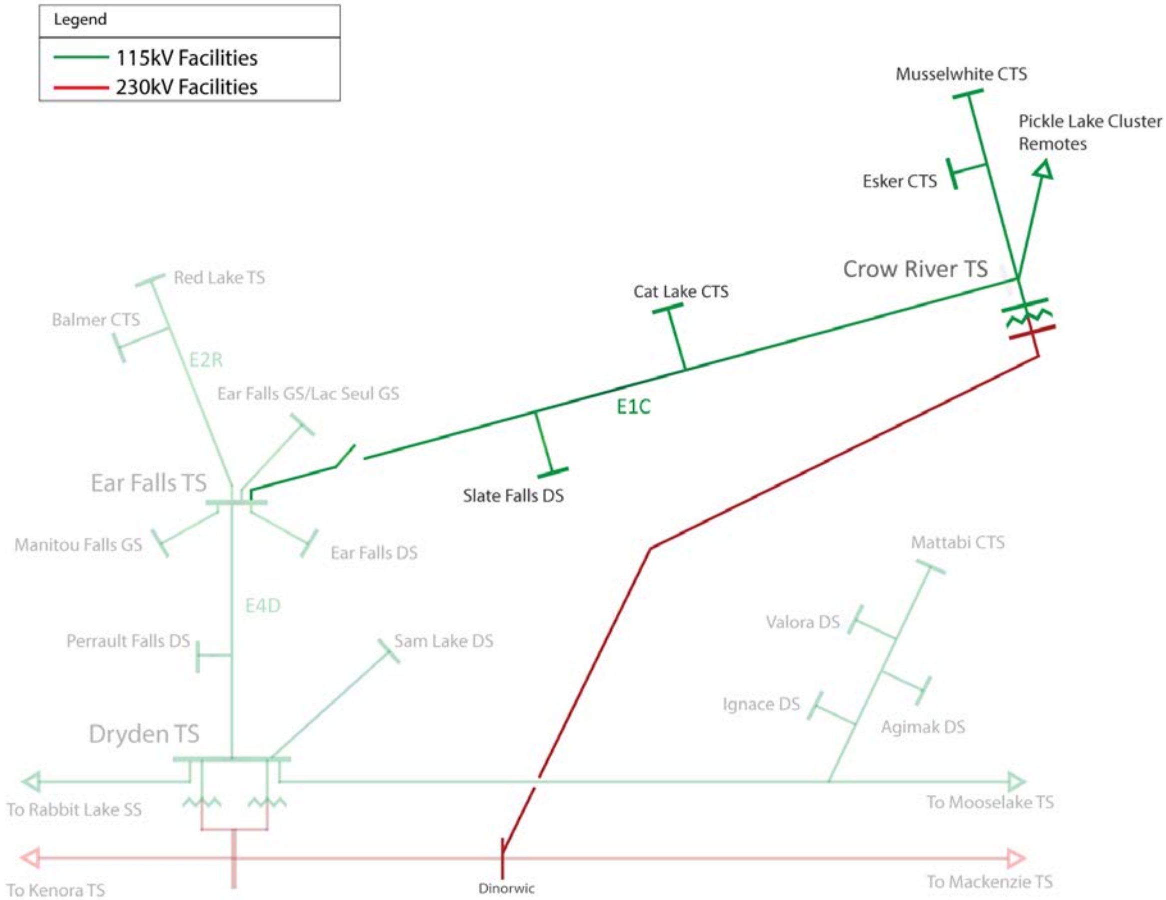
This option is to install a new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker running to Pickle Lake terminating at Crow River DS or at a new 230 kV station where a new 230/115 kV autotransformer will be installed.

**Table 92: Summary of Load Meeting Capability**

| Option | Incremental Capacity | Load Meeting Capability | Low Forecast Demand | Reference Forecast Demand | High Forecast Demand |
|---|---|---|---|---|---|
| New 230 kV line from Dryden/Ignace to Pickle Lake | 136 MW | 160 MW | 48 MW | 78 MW (100 MW) | 90 MW (156 MW) |

A diagram of this option is shown in Figure 33 below.

**Figure 33: New 230 kV line to Pickle Lake Diagram**




A summary of the cost for this option can be found in Table 93 and Table 94 below.

Table 94 shows an illustration of the peak load flow case for the new 230 kV line to Pickle Lake option. The voltage in the Pickle Lake area is maintained in a range of 240 kV to 245 kV, which helps to maintain voltages on existing and planned facilities within a healthy range.

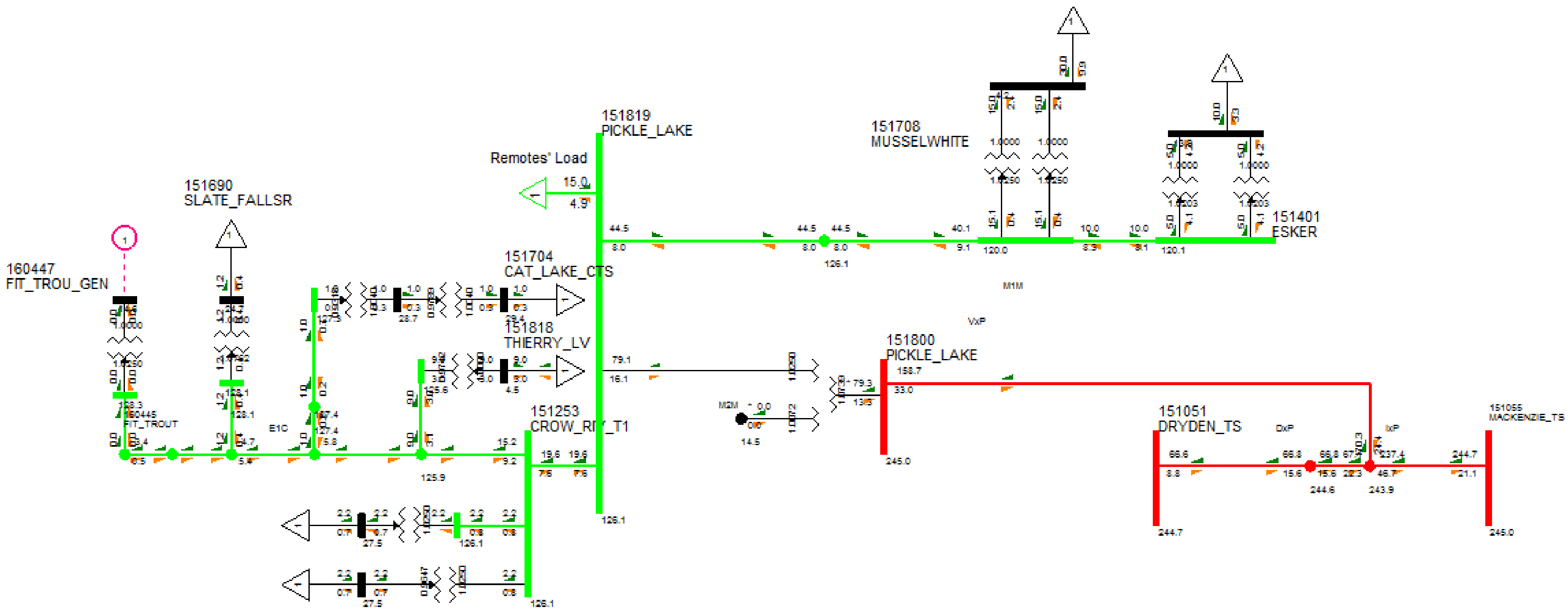
## Table 93: 230 kV line to Pickle Lake Cost Summary for LMC up to 78 MW

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | 138 | | | | | | | | | | | | | | | | |
| Station cost | | | | 28.4 | | | | | | | | | | | | | | | | |
| O&M | | | | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 168.3 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 |
| Annual Amortized Cost | | | | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 | 9.4 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 8.4 | 16.4 | 24.1 | 31.5 | 38.7 | 45.5 | 52.1 | 58.5 | 64.6 | 70.5 | 76.1 | 81.5 | 86.8 | 91.8 | 96.6 | 101.2 | 105.7 |

## Table 94: 230 kV line to Pickle Lake Cost Summary for LMC up to 90 MW

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | 138 | | | | | | | | | | | | | | | | |
| Station cost | | | | 42.2 | | | | | | | | | | | | | | | | |
| O&M | | | | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 182.2 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Annual Amortized Cost | | | | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 9.0 | 17.7 | 26.1 | 34.1 | 41.9 | 49.3 | 56.5 | 63.3 | 69.9 | 76.3 | 82.4 | 88.3 | 93.9 | 99.4 | 104.6 | 109.6 | 114.4 |

**Figure 34: 230 kV Line Option Pickle Lake Subsystem Configuration**

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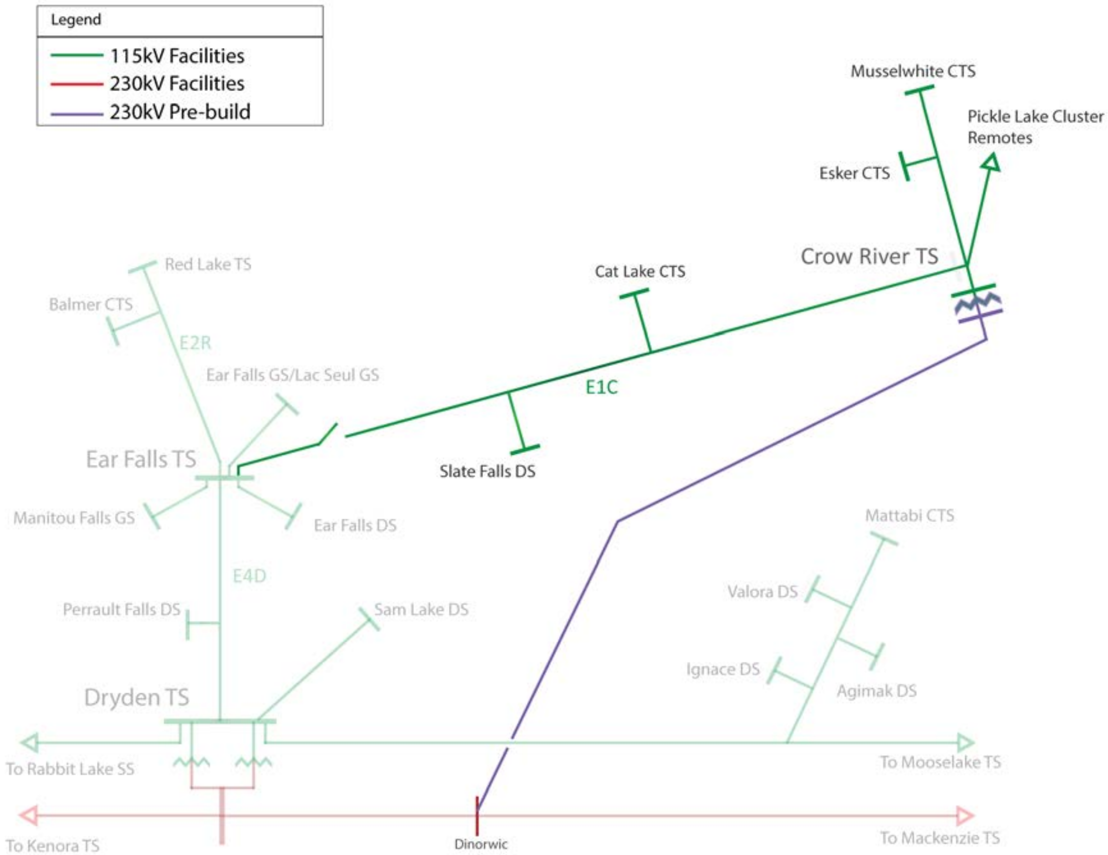
### *Pre-build 230 kV Line to Pickle Lake*

This option would pre-build a new single circuit line to 230 kV standards (230 kV structures and hardware) and connect it to the 115 kV system on M2D east Dryden with an in-line breaker and running to Pickle Lake where it would terminate at Crow River DS. When additional capacity is required, the line would be reterminated on the regional 230 kV system (D26A) east of Dryden and a 230/115 kV autotransformer would be installed either at Crow River DS or at a new TS in Pickle Lake.

| Option | Incremental Capacity | Load Meeting Capability | Low Forecast Demand | Reference Forecast Demand | High Forecast Demand |
|---|---|---|---|---|---|
| Pre-build 230 kV line from Dryden/Ignace to Pickle Lake:<br><br>Stage 1: operated at 115 kV<br><br>Stage 2: operated at 230 kV | 46 MW<br><br>90 MW | 70 MW<br><br>160 MW | 48 MW | 78 MW (100 MW) | 90 MW (156 MW) |

Figure 35 provides a diagram of the area with this option, while Table 95 provides a summary of costs and timing for this option.

**Figure 35: Pre-build 230 kV Line to Pickle Lake Option**




Note: the above diagram illustrates the second stage configuration (operated at 230 kV).

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### Table 95: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 1

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | 138 | | | | | | | | | | | | | | | | |
| Station cost | | | | 16.6 | | | | | | | | | | | | | | | | |
| O&M | | | | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 156.3 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Annual Amortized Cost | | | | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 7.8 | 15.2 | 22.4 | 29.3 | 35.9 | 42.3 | 48.4 | 54.3 | 60.0 | 65.5 | 70.7 | 75.8 | 80.6 | 85.3 | 89.7 | 94.1 | 98.2 |

### Table 96: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 2 for LMC up to 78 MW

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | | | | | | | | | | | | | | | |
| Station cost | | | | | | | | | | 14.0 | | | | | | | | | | |
| O&M | | | | | | | | | | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 14.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Annual Amortized Cost | | | | | | | | | | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.6 | 1.1 | 1.6 | 2.1 | 2.6 | 3.0 | 3.5 | 3.9 | 4.3 | 4.7 | 5.1 |

### Table 97: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 2 for LMC up to 90 MW

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | | | | | | | | | | | | | | | |
| Station cost | | | | | | | | | | 26.0 | | | | | | | | | | |
| O&M | | | | | | | | | | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 26.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Annual Amortized Cost | | | | | | | | | | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.0 | 2.0 | 3.0 | 3.9 | 4.8 | 5.6 | 6.4 | 7.2 | 8.0 | 8.7 | 9.4 |

### 10.8.3 Ring of Fire Subsystem Transmission Options

The following table summarizes the capability of various transmission options to meet the forecasted demand levels for the Ring of Fire sub-system for the reference, high, and low scenarios:

| Option | Incremental Capacity | Load Meeting Capability | Low Forecast Demand | Reference Forecast Demand | High Forecast Demand |
|---|---|---|---|---|---|
| *East-West corridor* | | | 7 MW | 29 MW | 73 MW |
| 115 kV line from Pickle Lake | 60 MW | 60 MW | | | |
| 230 kV line from Pickle Lake | 78 MW | 78 MW | | | |
| *North-South corridor* | | | | | |
| 230 kV line from Marathon TS | 78 MW | 78 MW | | | |
| 230 kV line from east of Nipigon | 78 MW | 78 MW | | | |

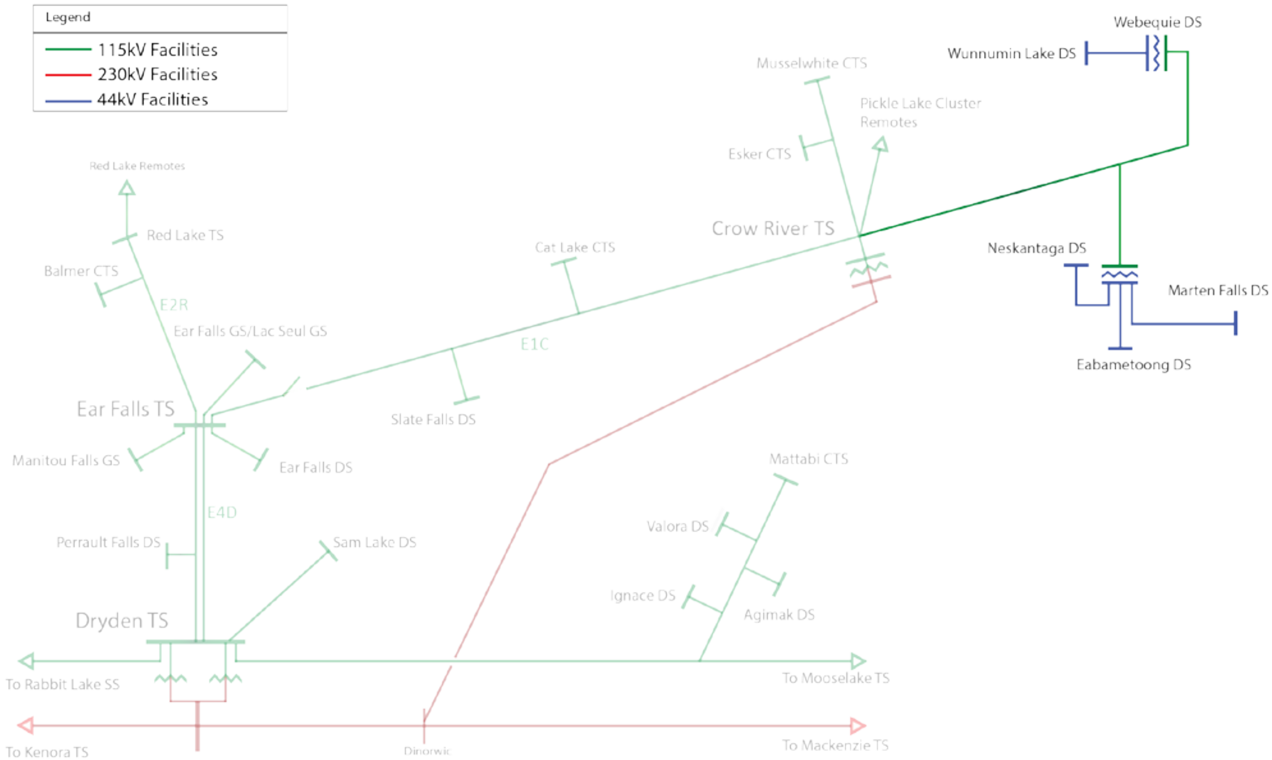
The options and costs of the options are discussed in further detail below.

#### *115 kV Line Connection for Ring of Fire Remote Communities from Pickle Lake*

In a scenario where mines at the Ring of Fire do not connect to the transmission system, it has been assumed that the 5 remote communities in the Ring of Fire subsystem would develop a connection to Pickle Lake, based on the findings of the draft Remote Community Connection Plan. This option is to build a 115 kV line from Pickle Lake to a point near Webequie FN passing near Neskantaga FN. Neskantaga FN, Eabametoong FN and Marten Falls FN would connect by distribution lines to a new transformer station near Neskantaga FN, while Nibinamik FN and Webequie FN would connect by distribution line to a transformer station near Webequie FN.

Figure 36, provides an illustrative schematic of this option, while costs are provided in Table 98.

### Figure 36: 115 kV Line from Pickle Lake to Matawa Remotes

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### Table 98: 115 kV line from Pickle Lake to Ring of Fire Subsystem Remote Communities Cost Summary

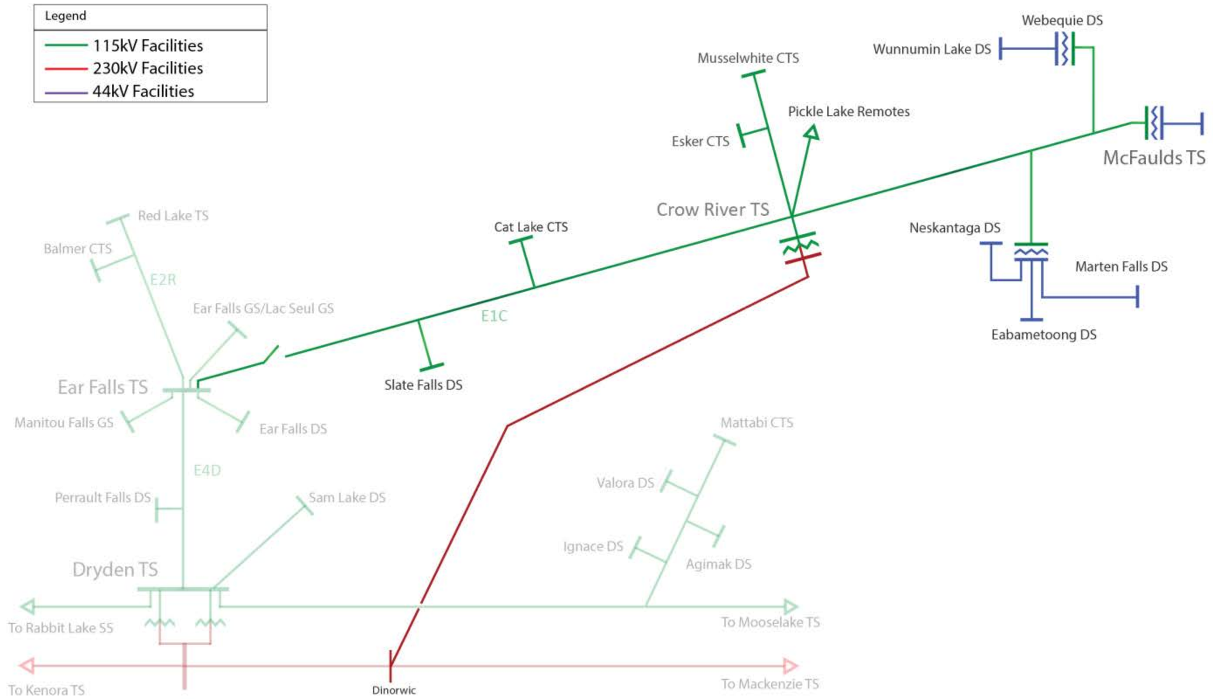
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | 94.3 | | | | | | | | | | | | | | |
| Station cost | | | | | | 6.6 | | | | | | | | | | | | | | |
| O&M | | | | | | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 101.9 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Annual Amortized Cost | | | | | | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4.7 | 9.2 | 13.5 | 17.7 | 21.6 | 25.5 | 29.2 | 32.7 | 36.2 | 39.4 | 42.6 | 45.6 | 48.6 | 51.4 | 54.1 |
| Line to Pickle Lake Portion | 0.0 | 0.0 | 0.0 | 0.7 | 1.3 | 1.9 | 2.5 | 3.0 | 3.6 | 4.1 | 4.6 | 5.1 | 5.5 | 6.0 | 6.4 | 6.8 | 7.2 | 7.6 | 8.0 | 8.3 |
| NPV with PL Line | 62.4 | | | | | | | | | | | | | | | | | | | |

### *115 kV Line from Pickle Lake to Ring of Fire*

This option considers building a new 115 kV line from Pickle Lake to the Ring of Fire mining development area, and connecting the five remote communities in the Ring of Fire subsystem. The feasibility of this option is contingent on the completion of a new 230 kV line from east of Dryden to Pickle Lake. Power flow studies show that a single circuit 115 kV line from Pickle Lake could supply up to 60 MW of mining load at the Ring of Fire plus 7 MW of remote community load.

Figure 37, shows this option with the Pickle Lake subsystem.

**Figure 37: 115 kV Line from Pickle Lake to Ring of Fire**




A prorated portion of the costs for new a 230 kV transmission line and 230/115 kV transformer station from the Dryden area to Pickle Lake is included in the cost of this option because it is required for this option to be undertaken as is shown in the cost summary in Table 99.

Figure 38 provides the peak load flow for the North of Dryden sub-region, illustrating that voltages throughout the subsystem are maintained in a healthy range of 120 kV to 125 kV.

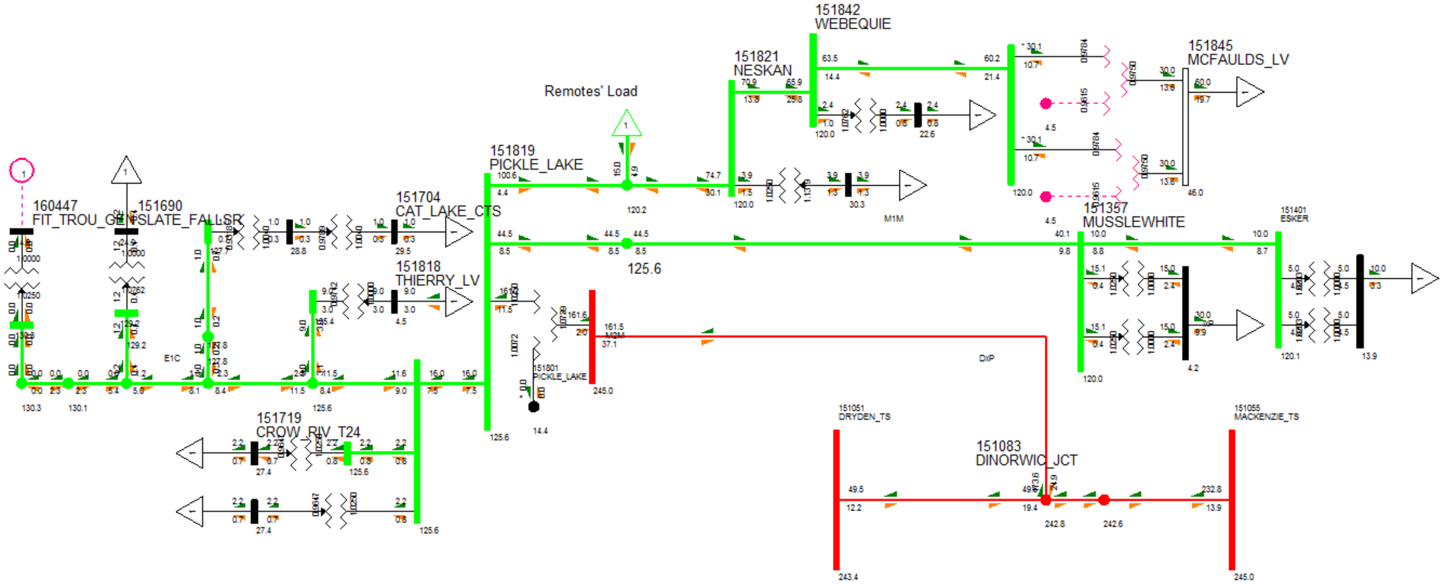
**Table 99: 115 kV line from Pickle Lake to Ring of Fire Cost Summary for LMC up to 29 MW**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | 132 | | | | | | | | | | | | | | |
| Station cost | | | | | | 13.6 | | | | | | | | | | | | | | |
| O&M | | | | | | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 147.4 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Annual Amortized Cost | | | | | | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 | 8.2 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6.8 | 13.3 | 19.5 | 25.5 | 31.3 | 36.9 | 42.2 | 47.4 | 52.3 | 57.1 | 61.6 | 66.0 | 70.3 | 74.3 | 78.2 |
| Line to Pickle Lake Portion | 0.0 | 0.0 | 0.0 | 2.2 | 4.3 | 6.3 | 8.2 | 10.1 | 11.9 | 13.6 | 15.3 | 16.9 | 18.4 | 19.9 | 21.3 | 22.7 | 24.0 | 25.2 | 26.4 | 27.6 |
| NPV with PL Line | 105.8 | | | | | | | | | | | | | | | | | | | |

**Table 100: 115 kV line from Pickle Lake to Ring of Fire Cost Summary for LMC up to 51 MW**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | 132 | | | | | | | | | | | | | | |
| Station cost | | | | | | 23.2 | | | | | | | | | | | | | | |
| O&M | | | | | | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 157.1 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 |
| Annual Amortized Cost | | | | | | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 7.2 | 14.1 | 20.8 | 27.2 | 33.4 | 39.3 | 45.0 | 50.5 | 55.8 | 60.8 | 65.7 | 70.4 | 74.9 | 79.2 | 83.4 |
| Line to Pickle Lake Portion | 0.0 | 0.0 | 0.0 | 3.2 | 6.3 | 9.2 | 12.1 | 14.8 | 17.5 | 20.0 | 22.4 | 24.8 | 27.0 | 29.2 | 31.3 | 33.3 | 35.2 | 37.0 | 38.8 | 40.5 |
| NPV with PL Line | 123.9 | | | | | | | | | | | | | | | | | | | |

## Figure 38: 115 kV Line from Pickle Lake Option Ring of Fire Subsystem Configuration

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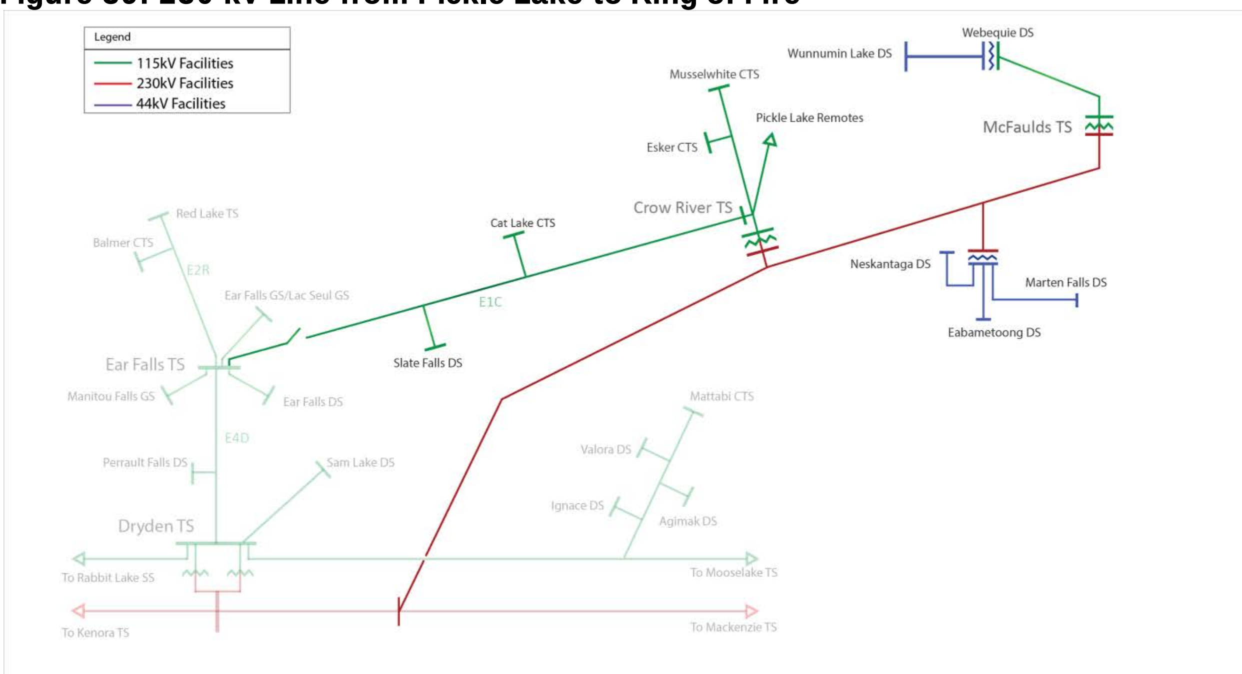
### *230 kV Line from Pickle Lake to Ring of Fire*

This option considers building a new 230 kV single circuit line from a new 230 kV station at Pickle Lake to the Ring of Fire, and a new 230/115 kV TS near Neskantaga FN and at the Ring of Fire. The feasibility of this option is contingent on the completion of a new 230 kV line from east of Dryden to Pickle Lake. This line would enable the connection of the five Matawa remote communities in the Ring of Fire subsystem as well as serve the high growth scenario (MW) for mining load at the Ring of Fire. Figure 39 shows the Pickle Lake and Ring of Fire subsystems with a new 230 kV line from the Dryden area to Pickle Lake and this option for a new 230 kV line from Pickle Lake to the Ring of Fire. Figure 39, shows this option implemented with the Pickle Lake subsystem.

**Figure 39: 230 kV Line from Pickle Lake to Ring of Fire**

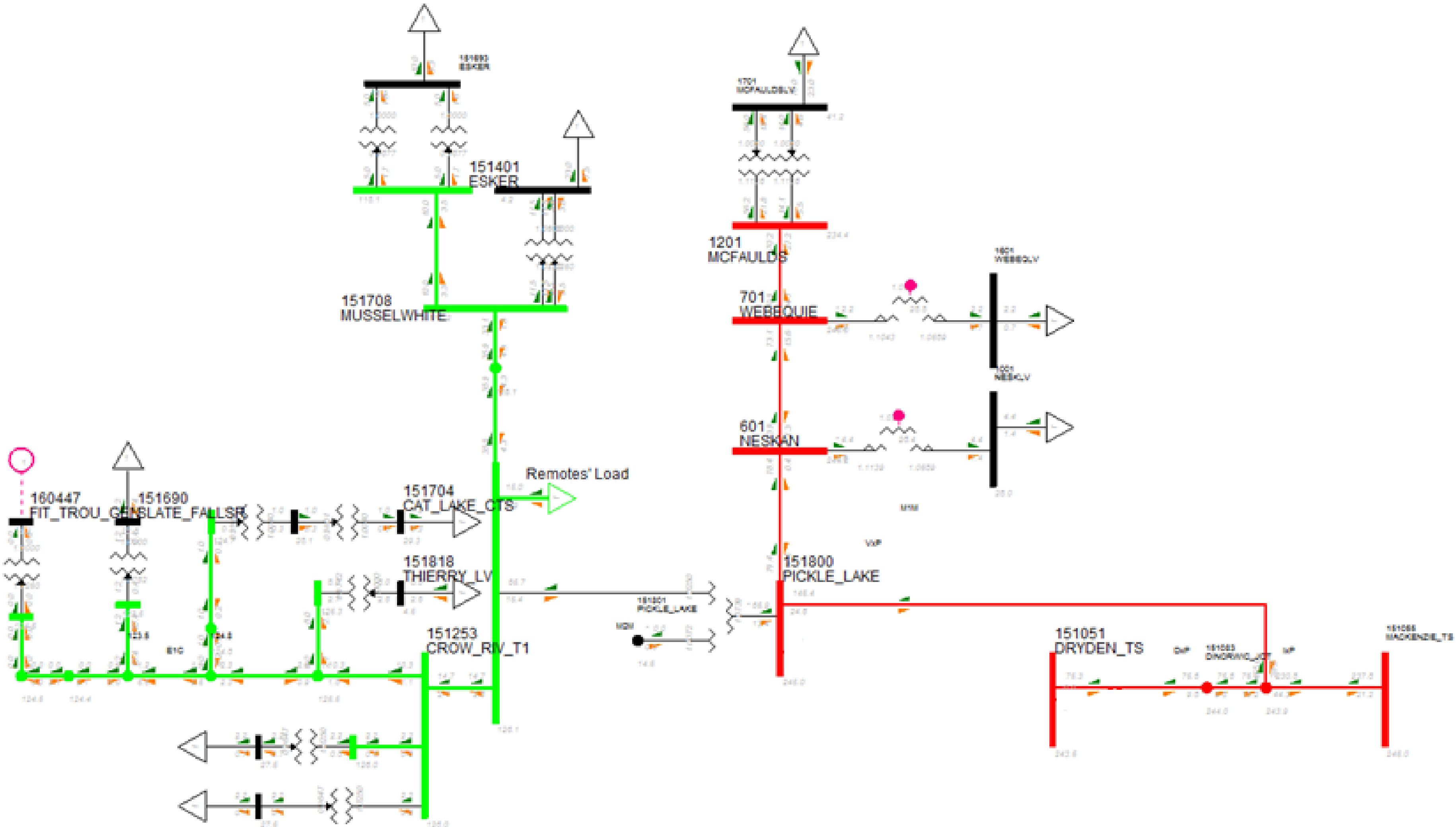



A prorated portion of the costs for new a 230 kV transmission line and station from the Dryden area to Pickle Lake is included in the cost of this option, as shown in the cost summary in Table 101 below.

**Table 101: 230 kV line from Pickle Lake to Ring of Fire Cost Summary**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | 165 | | | | | | | | | | | | | | |
| Station cost | | | | | | 30.4 | | | | | | | | | | | | | | |
| O&M | | | | | | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 197.7 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| Annual Amortized Cost | | | | | | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 9.1 | 17.8 | 26.2 | 34.3 | 42.0 | 49.5 | 56.6 | 63.5 | 70.2 | 76.5 | 82.7 | 88.6 | 94.2 | 99.7 | 104.9 |
| Line to Pickle Lake Portion | 0.0 | 0.0 | 0.0 | 4.1 | 8.0 | 11.8 | 15.4 | 18.9 | 22.2 | 25.4 | 28.5 | 31.5 | 34.4 | 37.1 | 39.7 | 42.3 | 44.7 | 47.1 | 49.4 | 51.5 |
| NPV with PL Line | 156.4 | | | | | | | | | | | | | | | | | | | |

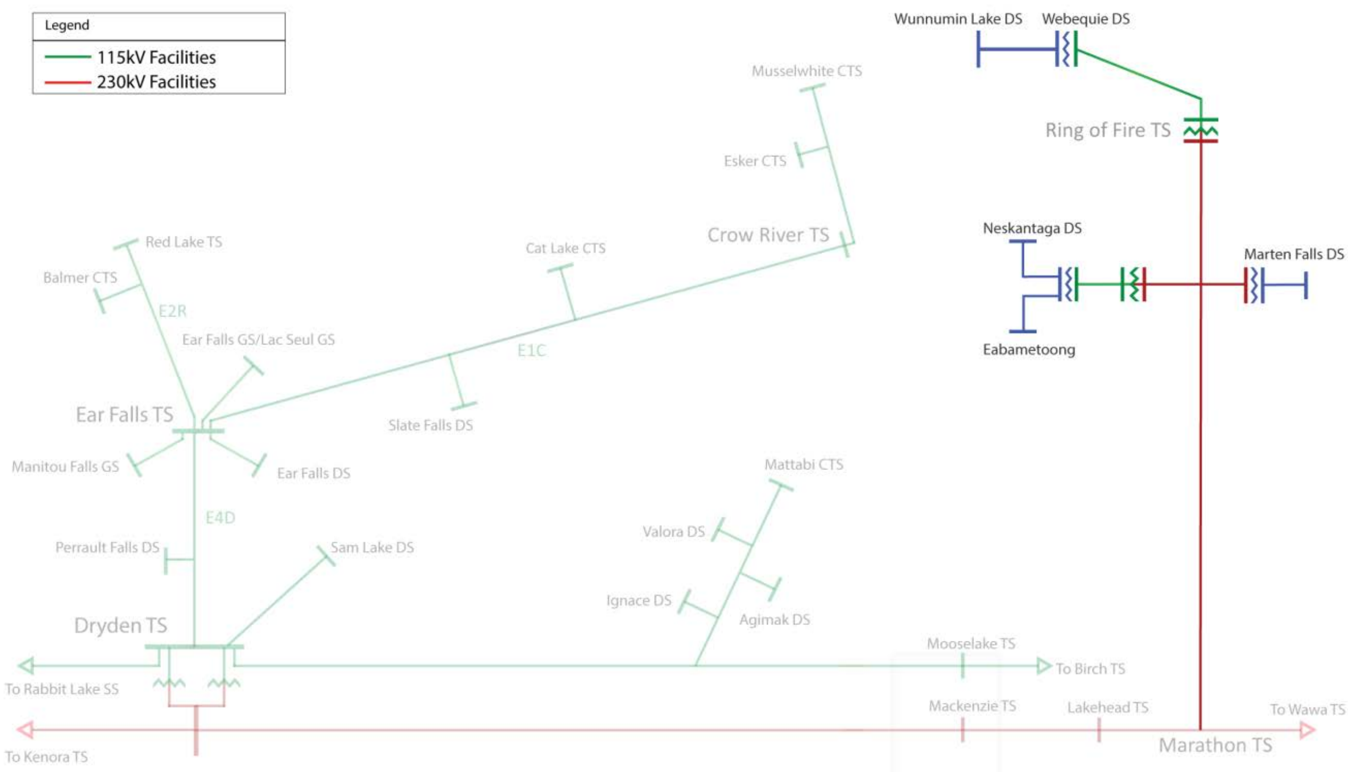
**Figure 40: 230 kV Line from Pickle Lake Option Ring of Fire Subsystem Configuration**



### *230 kV Line from Marathon TS or east of Nipigon to Ring of Fire*

Given the potential for a new all season road to serve the Ring of Fire mining development area from around Nakina, this option was developed to leverage the availability of the all season road assuming they can share a common right of way from Nakina. The existing transmission supply serving the Long Lac\Nakina area is the single circuit 115 kV line A4L, which has insufficient capability to serve the forecast load growth of the Ring of Fire subsystem. Therefore, a new 230 kV single circuit transmission line from either Marathon TS or east of Nipigon would be required for this option. These options have similar line lengths and are expected to have approximately the same costs. A diagram of this option is provided in Figure 41 below.

**Figure 41: 230 kV Line from Marathon or East of Nipigon to Ring of Fire**

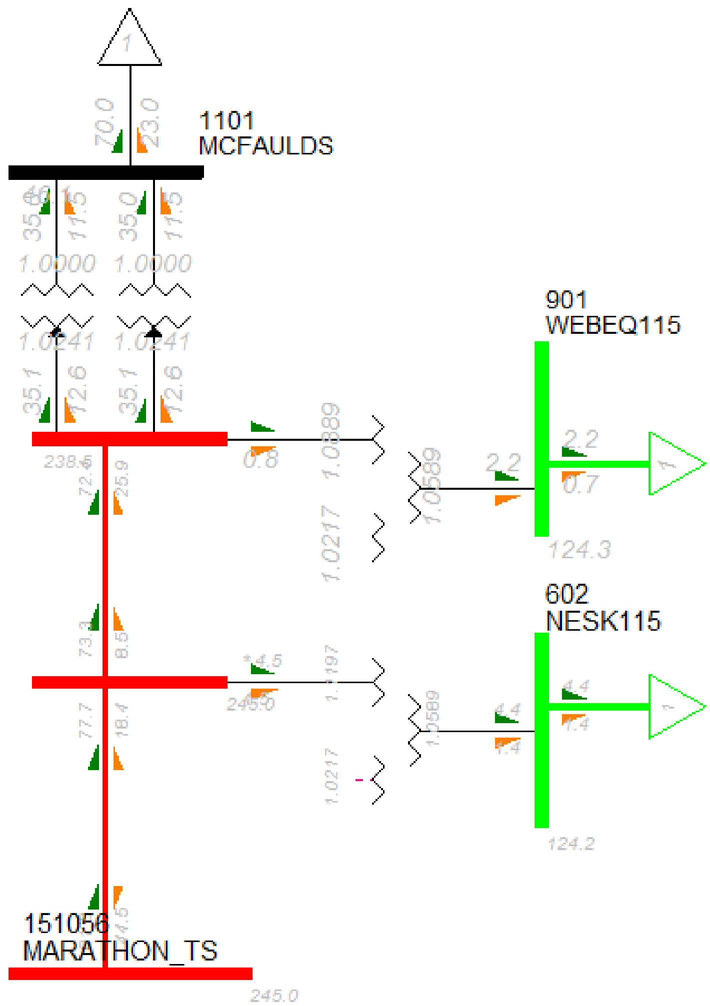


The LMC of the Ring of Fire subsystem for this option is 77 MW. This includes 7 MW for the communities on the line as well as 70 MW at the Ring of Fire. A summary of the cost for this option can be found in Table 102 below.

**Table 102: 230 kV line from Marathon TS or east of Nipigon to Ring of Fire Cost Summary**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line cost | | | | | | 262 | | | | | | | | | | | | | | |
| Station cost | | | | | | 64.7 | | | | | | | | | | | | | | |
| O&M | | | | | | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 |
| Total Annual Cost | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 330.0 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 |
| Annual Amortized Cost | | | | | | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 | 18.4 |
| Cumulative PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 15.1 | 29.7 | 43.7 | 57.2 | 70.1 | 82.6 | 94.6 | 106.1 | 117.1 | 127.8 | 138.0 | 147.9 | 157.3 | 166.4 | 175.2 |
| NPV | 175.2 | | | | | | | | | | | | | | | | | | | |

**Figure 42: 230 kV Line from Marathon Option Ring of Fire Subsystem Configuration**

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# 11 OTHER REPORTS PROVIDED

## 11.1 IESO/OPA North of Dryden and Remote Communities Study – May 2012

## 11.2 Draft Remote Community Connection Plan – August 2012

## 11.3 Unit Cost Estimates for Transmission Lines and Facilities in Northern Ontario and the Far North – SNC Lavalin T&D, 2011

## 11.4 Draft Remote Community Connection Plan – August 2014

# Appendix C: Order-in-Council from the Minister of Energy

**Ministry of Energy**

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

**Ministère de l'Énergie**

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

July 29, 2016

Ms Rosemarie Leclair
Chair and Chief Executive Officer
Ontario Energy Board
2300 Yonge Street
PO Box 2319
Toronto ON M4P 1E4

Dear Ms Leclair:

The connection of remote First Nation communities was identified as a priority project in the 2013 Long-Term Energy Plan. This project will reduce reliance on diesel generation and bring a number of environmental, social and economic benefits to these First Nation communities. Under the authority of section 28.6.1 of the *Ontario Energy Board Act, 1998,* I have, with the approval of the Lieutenant Governor in Council, issued a directive with regard to the expansion of the transmission system by developing the Remotes Connection Project and the Line to Pickle Lake.

The Directive was approved by Order-in-Council on July 19, 2016, and both the Order-in-Council and Directive are attached to this letter. Please do not hesitate to contact my office with any questions.

Sincerely,

Glenn Thibeault
Minister

Enclosures

c: Dan Moulton, Senior Advisor (Communications), Ministry of Energy

Ontario

**Order in Council**
**Décret**

On the recommendation of the undersigned, the Lieutenant Governor of Ontario, by and with the advice and concurrence of the Executive Council of Ontario, orders that:

Sur la recommandation de la personne soussignée, la lieutenante-gouverneure de l'Ontario, sur l'avis et avec le consentement du Conseil exécutif de l'Ontario, décrète ce qui suit:

**WHEREAS** Ontario's 2013 Long-Term Energy Plan stated that the connection of twenty one remote First Nation communities and the Line to Pickle Lake are priorities for Ontario.

**AND WHEREAS** Ontario has determined the benefit of expanding Ontario's transmission system in order to connect the sixteen remote First Nation communities in Appendix A to the provincial electricity grid (the "Remotes Connection Project");

**AND WHEREAS** the Remotes Connection Project will also require enhancement of the existing transmission system that includes a new transmission line originating in or at a point between Ignace and Dryden to increase supply to Pickle Lake (the Line to Pickle Lake);

**AND WHEREAS** the Government has determined that the Remotes Connection Project and the Line to Pickle Lake should be undertaken by a transmitter that is best positioned to connect remote First Nation communities in the most timely and cost-efficient manner that protects ratepayer interests;

**AND WHEREAS** the Government has determined that the preferred manner of proceeding is to require 2472883 Ontario Limited on behalf of Wataynikaneyap Power LP to undertake the development of the Line to Pickle Lake and the Remotes Connection Project, including any and all steps which are deemed to be necessary and desirable in order to seek required approvals;

**AND WHEREAS** the Minister of Energy has, with the approval of the Lieutenant Governor in Council, the authority to issue Directives pursuant to section 28.6.1 of the *Ontario Energy Board Act, 1998,* which relate to the construction, expansion or re-enforcement of transmission systems;

**NOW THEREFORE** the Directive attached hereto is approved.

--------

**ATTENDU QUE** le plan énergétique à long terme de l'Ontario de 2013 a indiqué que le branchement de vingt-et-une collectivités éloignées des Premières Nations et la ligne vers Pickle Lake constituent des priorités pour l'Ontario.

**ET ATTENDU QUE** l'Ontario a déterminé l'avantage de prolonger le système de transport d'électricité de l'Ontario afin de brancher les seize collectivités éloignées des Premières Nations figurant à l'annexe A au réseau provincial d'électricité (« le projet de branchement des communautés éloignées »);

**ET ATTENDU QUE** le projet de branchement des communautés éloignées nécessitera également d'apporter des améliorations au système existant de transport d'électricité, y compris l'ajout d'une nouvelle ligne provenant d'un point entre Ignace et Dryden pour augmenter l'alimentation de Pickle Lake (la ligne vers Pickle Lake);

**ET ATTENDU QUE** le gouvernement a déterminé que le projet de branchement des communautés éloignées et la ligne vers Pickle Lake devraient être entrepris par le transporteur le mieux placé pour assurer le branchement des communautés éloignées des Premières Nations aussi rapidement et efficacement que possible afin d'assurer la protection des intérêts des usagers de l'électricité;

**ET ATTENDU QUE** le gouvernement a déterminé que la manière privilégiée pour ce faire est d'engager 2472883 Ontario Limited au nom de Wataynikaneyap Power LP pour entreprendre les travaux de la ligne de Pickle Lake et du projet de branchement des communautés éloignées, y compris toutes les étapes jugées nécessaires et souhaitables en vue de l'obtention des approbations nécessaires;

**ET ATTENDU QUE** le ministre de l'Énergie détient, avec l'approbation du lieutenant-gouverneur en conseil, l'autorité de publier des directives en vertu de l'article 28.6.1 de la *Loi de 1998 sur la*

*Commission de l'énergie de l'Ontario* liées à la construction, à l'expansion ou au renforcement des systèmes de transport d'électricité;

**POUR CES MOTIFS,** la directive jointe aux présentes est approuvée.

**Recommended:** Minister of Energy
**Recommandé par:** Ministre de l'Énergie

**Concurred:** Chair of Cabinet
**Appuyé par:** Le président/la présidente du Conseil des ministres,

**Approved and Ordered:**
**Approuvé et décrété le:** JUL 20 2016

**Lieutenant Governor**
**La lieutenante-gouverneure**

## MINISTER'S DIRECTIVE

## TO: THE ONTARIO ENERGY BOARD

I, Glenn Thibeault, hereby direct the Ontario Energy Board ("the Board") pursuant to section 28.6.1 of the *Ontario Energy Board Act, 1998* as follows:

1. The Board shall amend the conditions of 2472883 Ontario Limited on behalf of Wataynikaneyap Power LP's ("Wataynikaneyap Power LP") electricity transmission licence to include a requirement that Wataynikaneyap Power LP proceed to do the following related to expansion of the transmission system to connect the sixteen remote First Nation communities listed in Appendix A (collectively the "Remote Communities") to the provincial electricity grid:

    (i) Develop and seek approvals for a transmission line, which shall be composed of a new 230 kV line originating at a point between Ignace and Dryden and terminating in Pickle Lake (the "Line to Pickle Lake"). The development of the Line to Pickle Lake shall accord with the scope recommended by the Independent Electricity System Operator.

    (ii) Develop and seek approvals for the transmission lines extending north from Red Lake and Pickle Lake required to connect the Remote Communities to the provincial electricity grid. The development of these transmission lines shall accord with the scope supported by the Independent Electricity System Operator.

2. The Board shall require that Wataynikaneyap Power LP provide such reporting to the Board as the Board may consider appropriate, with respect to budget, timing, and risks in relation to the development of the projects referred to in paragraph 1.

3. The Board shall make the amendments to the electricity transmission licence of Wataynikaneyap Power LP without holding a hearing.

Minister of Energy

## Appendix A

1. Sandy Lake
2. Poplar Hill
3. Deer Lake
4. North Spirit Lake
5. Kee-Way-Win
6. Kingfisher
7. Wawakapewin
8. Kasabonika Lake
9. Wunnumin
10. Wapekeka
11. Kitchenuhmaykoosib Inninuwug
12. Bearskin Lake
13. Muskrat Dam Lake
14. Sachigo Lake
15. North Caribou Lake
16. Pikangikum

## DIRECTIVE DU MINISTRE

**DESTINATAIRE : COMMISSION DE L'ÉNERGIE DE L'ONTARIO**

Je, Glenn Thibeault, émets par les présentes à la Commission de l'énergie de l'Ontario (« la commission ») en vertu de l'article 28.6.1 de la *Loi de 1998 sur la Commission de l'énergie de l'Ontario* la directive suivante :

1. La commission modifiera les conditions du permis de 2472883 Ontario Limited au nom de Wataynikaneyap Power LP (« Wataynikaneyap Power LP ») pour exiger que Wataynikaneyap Power LP procède aux travaux nécessaires à l'expansion du système de transport d'éléctricité visant à brancher les seize collectivités éloignées des Premières Nations énumérées à l'annexe A (collectivement appelées « collectivités éloignées ») au réseau provincial d'électricité :

    (i) Définir et soumettre les demandes d'approbation d'une ligne de transport d'électricité, laquelle sera composée d'une nouvelle ligne de 230 kV provenant d'un point situé entre Ignace et Dryden et se terminant à Pickle Lake (la « ligne vers Pickle Lake »). La mise en place de la ligne vers Pickle Lake sera conforme à la portée recommandée par la Société indépendante d'exploitation du réseau d'électricité.

    (ii) Définir et soumettre les demandes d'approbation des lignes de transport d'électricité s'étendant au nord à partir de Red Lake et de Pickle Lake requises pour assurer le branchement des collectivités éloignées au réseau provincial d'électricité. La mise en place de ces lignes de transport sera conforme à la portée appuyée par la Société indépendante d'exploitation du réseau d'électricité.

2. La commission exigera de Wataynikaneyap Power LP qu'elle rende compte à la commission, comme la commission le juge approprié, relativement aux budgets, au calendrier et aux risques liés à la réalisation des projets énoncés au paragraphe 1.

3. La commission apportera les modifications nécessaires au permis de transport d'électricité de Wataynikaneyap Power LP sans tenir d'audience.

Ministre de l'Énergie

## Annexe A

1. Sandy Lake
2. Poplar Hill
3. Deer Lake
4. North Spirit Lake
5. Kee-Way-Win
6. Kingfisher
7. Wawakapewin
8. Kasabonika Lake
9. Wunnumin
10. Wapekeka
11. Kitchenuhmaykoosib Inninuwug
12. Bearskin Lake
13. Muskrat Dam Lake
14. Lac Sachigo
15. North Caribou Lake
16. Pikangikum

# Appendix D: Customer Satisfaction Survey Results

**Report on**
**Customer Service Research**

*Prepared for Hydro One*
*Remote Communities*

August 2015

**Viewpoints Research**
Winnipeg, Manitoba
(204) 988-9253
www.viewpoints.ca

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# EXECUTIVE SUMMARY

On behalf of Hydro One, Viewpoints Research conducted a telephone survey of 205 Hydro One Remote Communities' residential, business and government-supported organization customers from June to August 2015.

Where possible, the survey tracks findings from six previous waves of customer surveys conducted approximately every two years since 2003. Home Heating Sources

## Sources of Heating Energy

Almost two thirds of respondents indicated they heat their homes primarily with wood (64%), while 16% heat primarily with electricity, 14% with oil and 5% use propane.

A majority of respondents indicated they also use a secondary source of energy to heat their homes (56%), including 36% who use electricity, 11% who use wood, 6% who mentioned oil and 3% who said propane.

More than half of respondents mentioned electricity as either their primary or secondary source of home heating energy (51%).

## Appliances at Home

Eight in ten respondents have a clothes dryer (83%) and slightly fewer have an electric stove (79%), while 64% have a stand-alone freezer and 56% have an air conditioner.

Only one in three respondents have a block heater for their car or truck (33%).

## Satisfaction with Electrical Service

Overall satisfaction with the electrical service they receive from Hydro One Remotes, is 91%, similar to levels recorded in 2009 (91%) and 2011 (90%), but down from 2013's high of 97%.

## Reasons for Customer Satisfaction

Having electricity available when they want it continues to be the main driver of satisfaction with Hydro One electrical service (65%). Satisfaction with this attribute increased 11 points since 2013 (51%) and 25 points since 2009 (40%).

Approximately one in three customers attributed their satisfaction to good or improved service (20%), or improved reliability (12%). Satisfaction with customer service, generally, has held steady during this time, with one in ten customers indicating this is why they are satisfied (10%).

## Reasons for Customer Dissatisfaction

There were 13 dissatisfied customers in this research. High rates (85%) and unreliable service (31%) were mentioned as reasons these customers are not satisfied. These reasons are consistent with those given in past waves of research.

## Perceptions of Reliability

The proportion of customers who believe the reliability of their hydro service has improved in the past few years has remained at or above 24% since 2009. This year, 25% said they believe reliability has improved, while two thirds of customers said it has stayed about the same (67%).

## Bill Payment

More than 7 in 10 customers indicated they are the person who usually (67%) or sometimes (5%) pays the hydro bill.

Among those who said they usually or sometimes pays the hydro bill (N=134), perceptions regarding the accuracy of Hydro One's billing has dropped somewhat since 2013 but is still among the highest levels recorded since 2003. In this wave 25% said their Hydro One bill is always correct, down from 36% in 2013 but higher than 2011 when it was 22%. In addition, 48% of respondents said their bill is usually correct, for a total of 73%, down 6 points over 2013 results. In total, 13% of customers said their bills were either not correct very often (6%) or never correct (7%), up 7 points over 2013 results. Consistent with previous years, 15% of respondents were unsure how to answer this question.

## Customer Contact

Four in ten customers said they contacted Hydro One in the past year (42%) compared to 38% in 2013 and 44% in 2011. As in previous years, the most common reason customers contacted the utility was to discuss their bill (26%). Other reasons for contact include customers needing information (17%) or the power being out (9%).

Customer satisfaction with how Hydro One Remotes handled their contact dropped 12 points to 76% after 2013's record high of 88%, but is still the second highest satisfaction rating since tracking began. Those who said they were very satisfied with their contact with Hydro One is down 13 points to 33%, its lowest level since 2007 (25%).

## Factors Driving Perceptions & Satisfaction with Service

The research tested customers' agreement with a number of statements related to customer service, to explore customers' experiences and perceptions in key service areas. Hydro One Remote Communities scored best at **dealing with emergencies** (80% agree overall) and **staff being polite and friendly** (75%). Customers were less likely to agree that **when they call the Hydro One office someone usually answers quickly,** though a majority still agreed (62%).

Agreement with each of these statements dropped when compared to results in 2013 and, in the case of the first two statements, to their lowest levels since tracking began. Overall agreement with the third statement dropped three points to 62%, one point higher than its lowest level in 2011 (61%).

## What Hydro One Can Do to Improve Service to Customers

When asked what Hydro One Remotes could be doing to improve service to customers, the most frequently mentioned improvement is lowering rates (18%).

The desire for better communications was mentioned by 8% of respondents, while reducing the number of outages and using better equipment and supplies were each mentioned by 6% of respondents.

## Informing Customers of Planned Outages

The perception that Hydro One informs customers and communities when power will be turned off for scheduled maintenance and service improvements has dropped slightly since 2013. The view that Hydro One always informs them lost 11 points to 44%, while those who feel they do so usually is up 4 points to 31%, and those who say they are informed sometimes is up 2 points to 12%.

Those who feel Hydro One never informs customers about planned outages doubled to 8% since 2013.

## Staff is Polite & Helpful

Two thirds of customers indicated that Hydro One Remote Communities staff is generally polite and helpful when they come to their community to do things such as bring the electricity back on (66%), down 9 points since 2013 and at its lowest level since tracking began on this question in 2009. Just 1% of customers said staff are not polite and helpful, an improvement over 2013 (2%), 2011 (5%) and 2009 (3%).

## Awareness of Local Staff

Awareness of who the local Hydro One operator is steadily rising, up 8 points to 70% in this wave of research, while 30% do not know the local operator, down 7 points. Awareness is also higher than 2011 and 2009 when 59% said they knew who their local Hydro One operator was.

More than seven in ten respondents know who their meter reader is (73%), up 6 points from 2013 and at its highest level over four waves of tracking. One in three customers surveyed admitted they do not know their local meter reader (27%), down 7 points.

## Environmental Protection

Fewer than two thirds of respondents said Hydro One takes environmental protection in the community seriously (63%), down 3 points since 2013. About one in ten said Hydro One does not take it seriously (9%), also down 3 points since the last wave of research. More than one quarter of respondents were unsure (28%), up 6 points.

## Energy Efficiency Incentives

Asked if they are aware that Hydro One will provide them with mail-in rebates of up to $200 when they buy energy efficient appliances, three in ten said they know about this program (31%) but a majority of customers said they did not (69%).

Hydro One also operates a program called LEAP, which gives low-income residential customers up to $600 a year to help them pay their electricity bill to avoid disruptions to their service. Awareness of this program is up 6 points to 18% since 2013 but four in five respondents were not aware of the program (81%).

One in four respondents were aware that communities like theirs can generate renewable electricity through solar, wind or small hydro water projects and sell it back to Hydro One Remotes (25%), while almost three times as many were not aware of this opportunity (74%).

## Hydro Rates

A majority of Hydro One Remotes customers believe their Hydro rates are either the same as the rest of Ontario (32%) or higher (40%), while one in four are unsure (24%). Just 3% of customers believe their rates are lower.

A majority of Hydro One Remotes customers are not willing to pay more for electricity generated from renewable sources such as water, solar or wind (51%), while fewer than one in five said they would be (18%). Three in ten are unsure (31%).

## Communication Materials

Survey respondents were asked if they look at *Connected*, the newsletter Hydro One Remotes mails to them. More than four in ten respondents said they look at or read the newsletter (43%) and, of these (N=79), nine in ten said they find the information helpful or interesting (89%).

## Internet Access & Usage

Approximately two thirds of customers said they have regular access to the internet (64%), down 5 points from 2013, while a third do not (35%).

Among those customers with regular access (N=119), two thirds think they would be likely to use the internet to get information from Hydro One such as their electricity bill and information about planned power outages (66%). This is similar to 2013 results.

One in four said they would not use the internet to access this type of information (30%) while 4% could not say whether they would or would not use it, or said it would depend.

# GOALS & METHODOLOGY

## Goals

On behalf of Hydro One Remote Communities, Viewpoints Research conducted telephone interviews with the utility's residential, commercial and government-supported organization customers from June 22 to August 7, 2015. Many of the questions included in this survey have been tracked from earlier customer surveys administered about every two years since 2003. The research explored the following:

- Primary and secondary sources of home heating energy,
- The incidence of specific electric appliances in homes in served by Hydro One Remotes,
- Overall satisfaction with the electricity service provided by Hydro One (tracked since 2003),
- Customers' views on the accuracy of their bills (since 2005),
- Contact with Hydro One Remote Communities and perceptions of the utility's customer service. Customers who had contacted Hydro One in the past year were asked questions evaluating this specific experience, while all customers were asked to provide their general impressions (general questions tracked since 2005),
- Initiatives Hydro One could take to improve customer service,
- Awareness of local Hydro One staff,
- Perceptions of Hydro One's commitment to environmental protection in their communities,
- Perceptions of their electricity rates relative to others in the province and their openness to paying higher rates for electricity from renewable sources,
- Awareness and use of programs or services offered by Hydro One to help customers upgrade to energy efficient appliances and provide financial assistance for low income residential customers,
- Awareness of communications by Hydro One, and whether or not customers find the information helpful or interesting, and

- Internet access and the likelihood of internet usage among customers to retrieve billing information and alerts about planned power outages.

## Methodology

Sample was drawn from listed and unlisted telephone numbers in the Hydro One Remote Communities' service area. Hydro One Remote Communities has about 3,536 customers in 21 communities. This year 185 customers were interviewed, including 168 residential customers, 7 business customers and 10 government-supported organizations. The survey has an overall confidence level of ±7%, nineteen times out of twenty.

The findings of this research were cross tabulated by the following demographic and attitudinal variables:

- Community,
- Main heat source,
- Type of service (residential, commercial, government-supported organization),
- Satisfaction with electrical service,
- Whether or not customers have contacted Hydro One in the last year,
- Gender, and
- Age.

## Reporting

This summary report highlights the overall views and perceptions of Hydro One Remote Communities customers. When the attitudes of a particular set of customers is statistically different from customers overall, this will be noted in the report in a bulleted point. The report also compares the findings to results from 6 previous waves of research conducted every two years since 2003.

There are significant differences of opinion among residents of the different communities served by Hydro One Remote Communities, however these results should be interpreted with caution since the number of respondents in most communities is very small. Caution should be applied, generally, when considering differences among sub-groups with fewer than 100 respondents.

# SUMMARY OF RESEARCH FINDINGS

## Profile of Survey Respondents

The following table summarizes the demographic attributes of all respondents participating in the research since 2003. The characteristics of customers participating in this research have generally remained consistent over time.

Table 1: **Respondent Profile**

| Respondent Profile | 2015 | 2013 | 2011 | 2009* | 2007 | 2005 | 2003 |
|---|---|---|---|---|---|---|---|
| **Customer Type** | | | | | | | |
| Home | **91%** | 82% | 89% | 87% | 81% | 82% | 96% |
| Business | **4%** | 10% | 5% | 7% | 6% | 8% | 2% |
| Government funded | **6%** | 9% | 6% | 6% | 13% | 10% | 2% |
| **Age** | | | | | | | |
| 18 – 24 years | **7%** | 8% | 6% | 8% | 13% | 10% | 13% |
| 25 – 34 years | **15%** | 15% | 17% | 20% | 26% | 23% | 22% |
| 35 – 44 years | **12%** | 19% | 19% | 21% | 24% | 28% | 26% |
| 45 – 54 years | **23%** | 26% | 21% | 21% | 20% | 23% | 21% |
| 55 – 64 years | **22%** | 16% | 22% | 19% | 11% | 10% | 11% |
| 65 years and older | **22%** | 15% | 15% | 11% | 5% | 4% | 7% |
| **Gender** | | | | | | | |
| Men | **54%** | 50% | 56% | 60% | 54% | 56% | 54% |
| Women | **46%** | 50% | 44% | 40% | 46% | 44% | 46% |

Tallies may not equal 100%. Customers who were unsure are not included.

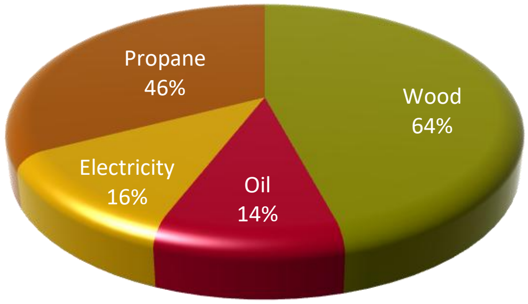
*Research conducted in 2009/2010 is reported as 2009 in this document.

## Home Heating Sources

### *Primary Source of Heating Energy*

Almost two thirds of respondents indicated they heat their homes primarily with wood (64%), while 16% heat primarily with electricity, 14% with oil and 5% use propane.

Chart 1: **Primary Source of Heating Energy**

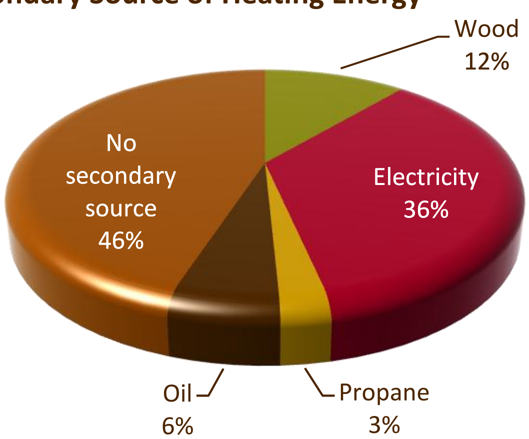



- Electricity is the primary source of heating energy in 100% of those interviewed in Hillsport/Mobert (4N). No respondents in the following communities heat primarily with electricity: Armstrong/Whitesands/Collins (3N), Bearskin Lake (9N), Fort Severn (5N), Gull Bay (9N), Lansdowne House/Neskantaga (6N), Marten Falls/Ogoki (2N), Sultan (14N), Wapekeka/Angling Lake (6N) and Webequie (7N).
- Men were more likely to say their households are heated primarily with wood (73% of 100N) than women (53% of 85N), while women were more likely to say their households are heated with electricity (20% vs. 12% men), propane (9% vs. 2% men) or oil (15% women vs. 13% men).

When asked, a majority of respondents indicated they also use a secondary source of energy to heat their homes (56%), including 36% who use electricity, 11% who use wood, 6% who mentioned oil and 3% who said propane.

More than half of respondents mentioned electricity as either their primary or secondary source of home heating energy (51%).

Chart 2: **Secondary Source of Heating Energy**

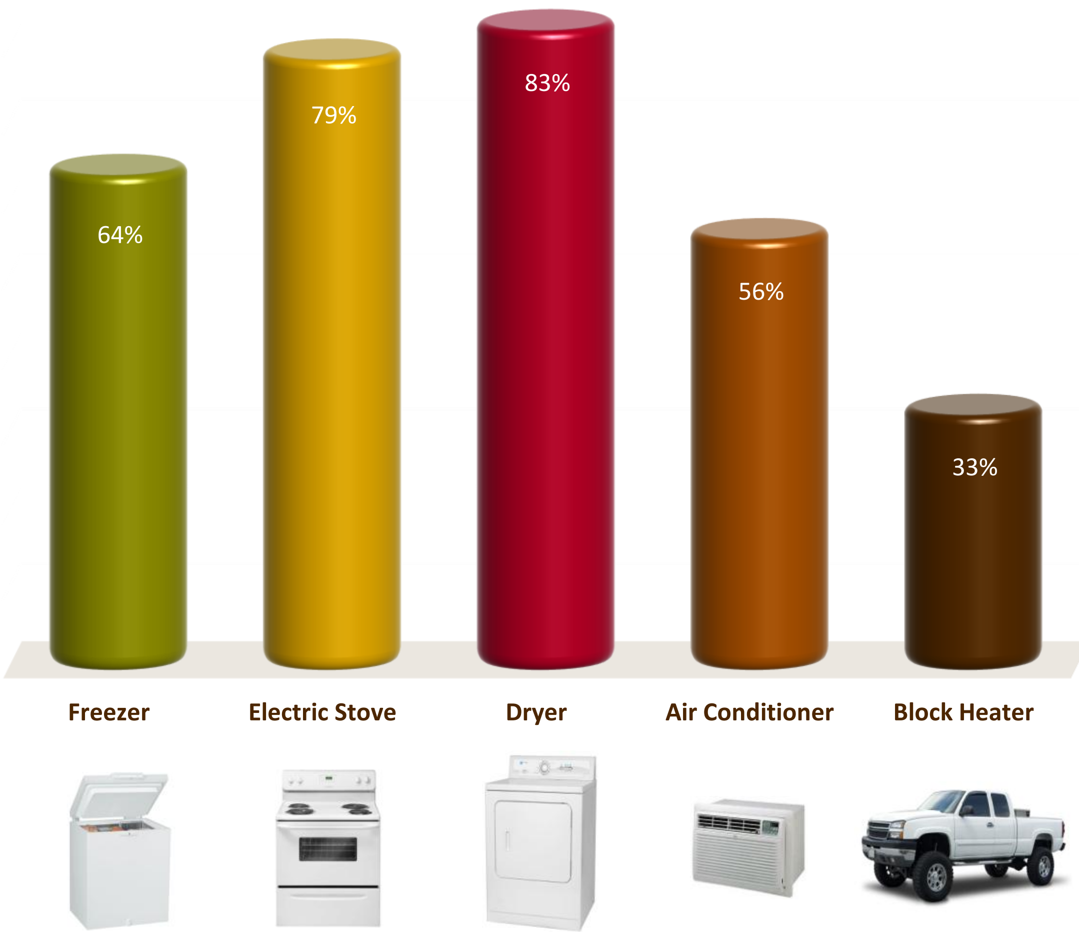


## Appliances at Home

Eight in ten respondents have a clothes dryer (83%) and slightly fewer have an electric stove (79%), while 64% have a stand-alone freezer and 56% have an air conditioner.

Only one in three respondents have a block heater for their car or truck (33%).

Chart 3: **Appliances at Home**

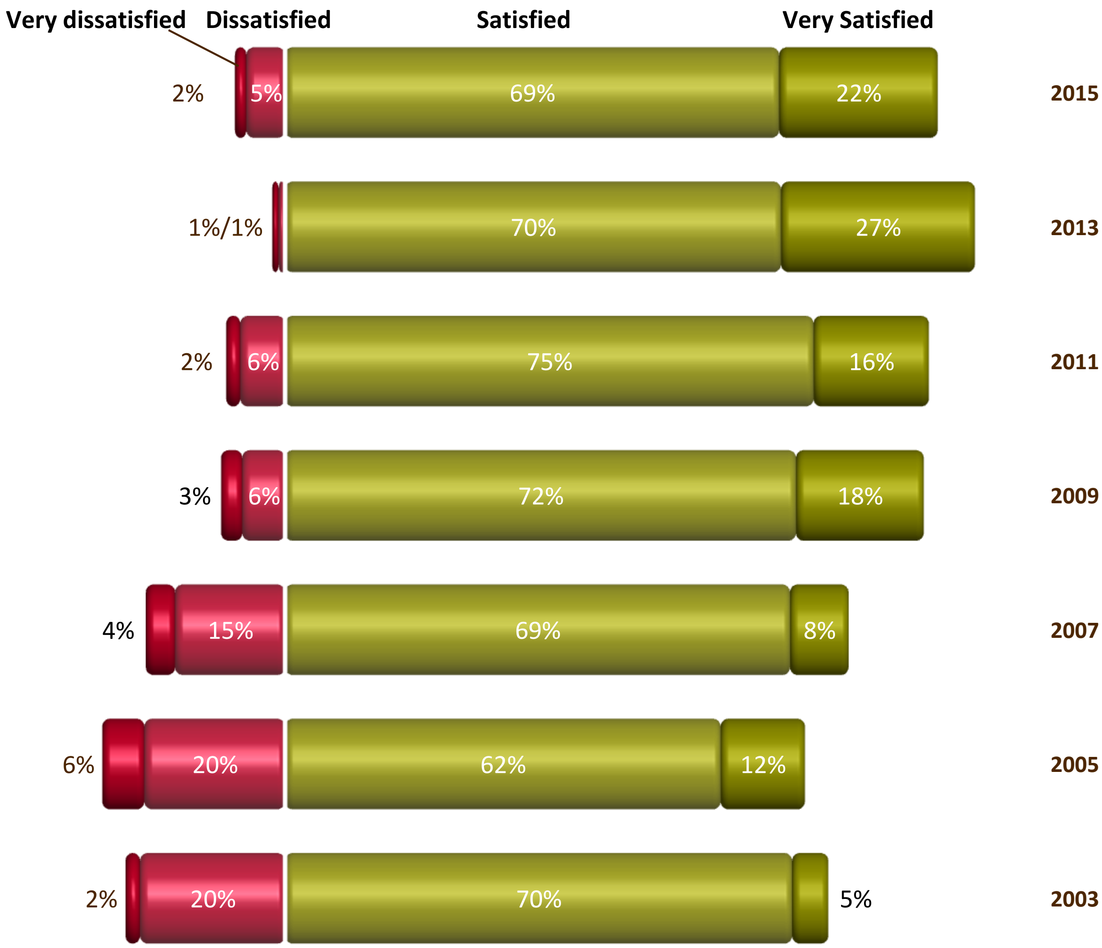



## Satisfaction with Electrical Service

### *Satisfaction with Electrical Service*

Overall satisfaction with the electrical service they receive from Hydro One Remotes, is 91%, similar to levels recorded in 2009 (91%) and 2011 (90%), but is down from 2013's high of 97%.

Chart 4: **Satisfaction with Electrical Service**




### *Reasons for Customer Satisfaction*

Having electricity available when they want it continues to be the main driver of satisfaction with Hydro One electrical service (65%). Satisfaction with this attribute increased 11 points since 2013 (51%) and 25 points since 2009 (40%).

Approximately one in three customers attributed their satisfaction to good or improved service (20%) or improved reliability (12%). Satisfaction with customer service, generally, has held steady during this time, with one in ten customers indicating this is why they are satisfied (10%).

Table 2 shows all the reasons for satisfaction mentioned and compares this year's results to past waves of research.

Table 2: **Reasons for Customer Satisfaction**

| Reasons for satisfaction | 2015 | 2013 | 2011 | 2009 | 2007 | 2005 | 2003 |
|---|---|---|---|---|---|---|---|
| Electricity there when needed | **65%** | 51% | 49% | 40% | 42% | 43% | 43% |
| Good/improved service | **20%** | 15% | 26% | 18% | 20% | 19% | 19% |
| Reliability has improved | **12%** | 17% | 25% | 20% | 12% | 10% | 10% |
| Fair rates | **4%** | 6% | 10% | 5% | 5% | 6% | 6% |
| Customer service | **10%** | 10% | 11% | 13% | 3% | 4% | 4% |
| Company doing the best they can | **4%** | 2% | 6% | 5% | 3% | 4% | 4% |
| Environmental practices | **0%** | 1% | 2% | 2% | <1% | 1% | 1% |
| Rates/problems not their fault | **1%** | NA | NA | NA | NA | NA | NA |
| No reason/other/unsure | **12%** | 19% | 10% | 27% | 26% | 26% | 26% |

Percentages do not total 100% because customers were permitted more than one response.

### *Reasons for Customer Dissatisfaction*

There were 13 dissatisfied customers in this research. High rates (85%) and unreliable service (31%) were mentioned as reasons these customers are not satisfied. These reasons are consistent with those given in past waves of research.

Table 3 summarizes the reasons given by customers for their dissatisfaction over the past six waves of research.

Table 3: **Reasons for Customer Dissatisfaction**

| Reasons for dissatisfaction | 2015 | 2013 | 2011 | 2009 | 2007 | 2005 | 2003 |
|---|---|---|---|---|---|---|---|
| **Rates** | | | | | | | |
| Expensive / high rates | **85%** | 50% | 56% | 48% | 64% | 73% | 63% |
| Rates discriminatory / unfair | **NA** | 25% | 8% | 4% | 9% | 14% | 13% |
| **Service Issues** | | | | | | | |
| Power not reliable | **31%** | 50% | 20% | 15% | 22% | 21% | 23% |
| Power quality problems, brownout / problems with appliances | **8%** | 25% | 4% | 11% | 5% | 7% | 21% |
| **Other** | | | | | | | |
| Don't like Hydro One | **NA** | NA | 0% | 5% | 5% | 8% | 3% |
| Bill is confusing | **NA** | 25% | 0% | 4% | 2% | 10% | 8% |
| Community / economy hurt by service / company | **NA** | 25% | 0% | 0% | 2% | 2% | 2% |
| Bad for environment / smelly / noisy | **NA** | 50% | 4% | 0% | 0% | 1% | 0% |
| No reason / other | **23%** | NA | 8% | 7% | 7% | 6% | 2% |

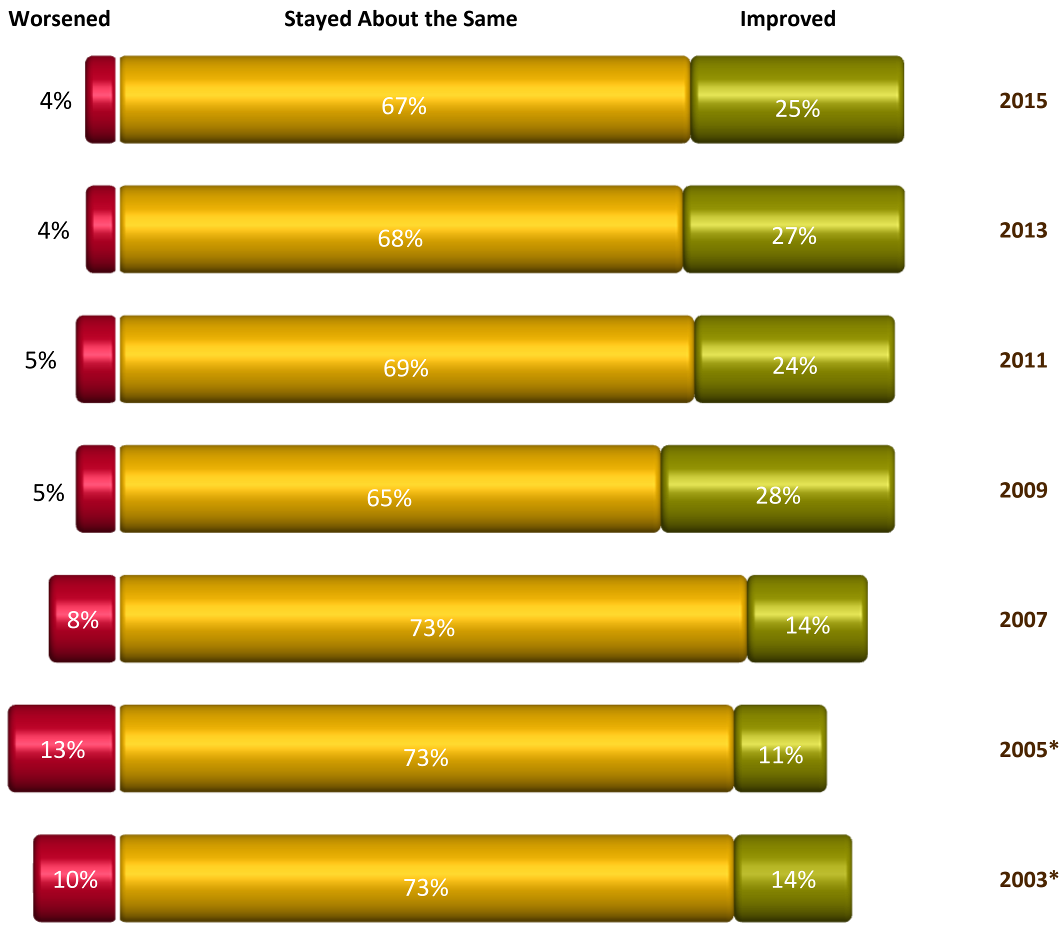
Percentages do not total 100% because customers were permitted more than one response.

### *Perceptions of Reliability*

After remaining stable below 15% from 2003 to 2007, the proportion of customers who believe the reliability of their hydro service has improved in the past few years has remained at or above 24% since. This year, 25% said they believe reliability has improved, while two thirds of customers said it has stayed about the same (67%). Since 2009, the proportion of customers who believe it has worsened has remained consistent at approximately one in twenty (4%).

The following chart illustrates changes in customers' impressions of their electrical service since 2003.

Chart 5: **Impressions of Reliability**




*In these years respondents were given the option to say that reliability has worsened/improved somewhat or a lot. These responses have been combined on this chart.

- Those most likely to think hydro reliability has improved reside in Marten Falls/Ogoki (100% on 2N), Webequie (57% 7N) and Kingfisher Lake (57% of 7N).
- Those most likely to think hydro reliability has worsened live in Hillsport/Mobert (50% of 4N) and Fort Severn (20% of 5N).
- Men are more likely to think hydro reliability has improved (34% vs. 14% women), while women are more likely to think it has stayed about the same (75% vs. 60% men).

## Bill Payment

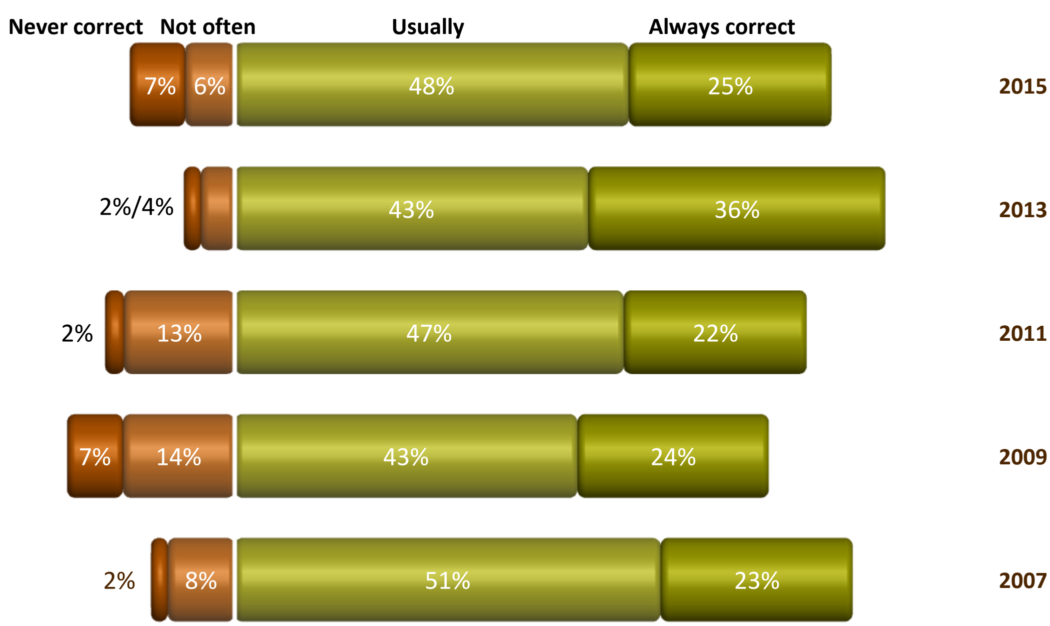
### *Billing Accuracy*

More than 7 in 10 customers indicated they are the person who usually (67%) or sometimes (5%) pays the hydro bill.

- Responsibility for paying the Hydro bill increases with age from 38% of those 18 to 34 (39N) to 79% of those 55+ (81N).
- Those who are responsible for paying the Hydro bill are more likely to have contacted Hydro last year (78% of 77N), compared to respondents overall (67%).
- Those contacted at home are more likely to be responsible for paying the Hydro bill (70% 168N) compared to those in government-supported organizations (50% of 10N) or businesses (29% of 7N).

Among those who said they usually or sometimes pays the hydro bill (N=134), perceptions regarding the accuracy of Hydro One's billing has dropped somewhat since 2013 but is still among the highest levels recorded since 2003. In this wave 25% said their Hydro One bill is always correct, down from 36% in 2013 but higher than 2011 when it was 22%. In addition, 48% of respondents said their bill is usually correct, for a total of 73%, down 6 points over 2013 results. In total, 13% of customers said their bills were either not correct very often (6%) or never correct (7%), up 7 points over 2013 results. Consistent with previous years, 15% of respondents were unsure how to answer this question.

Chart 6: **Billing Accuracy**



- Respondents contacted at government-supported organizations are more likely to feel their hydro bill is not very often correct (43% of 7N), than respondents overall (6%).

## Customer Contact

### *Incidence of Contact*

Four in ten customers said they contacted Hydro One in the past year (42%) compared to 38% in 2013 and 44% in 2011. As in previous years, the most common reason customers contacted the utility was to discuss their bill (26%). Other reasons for contact include customers needing information (17%) or the power being out (9%).

Table 4 shows all responses to this question and compares them to those from previous waves of research.

Table 4: **Customer Contact with Hydro One**

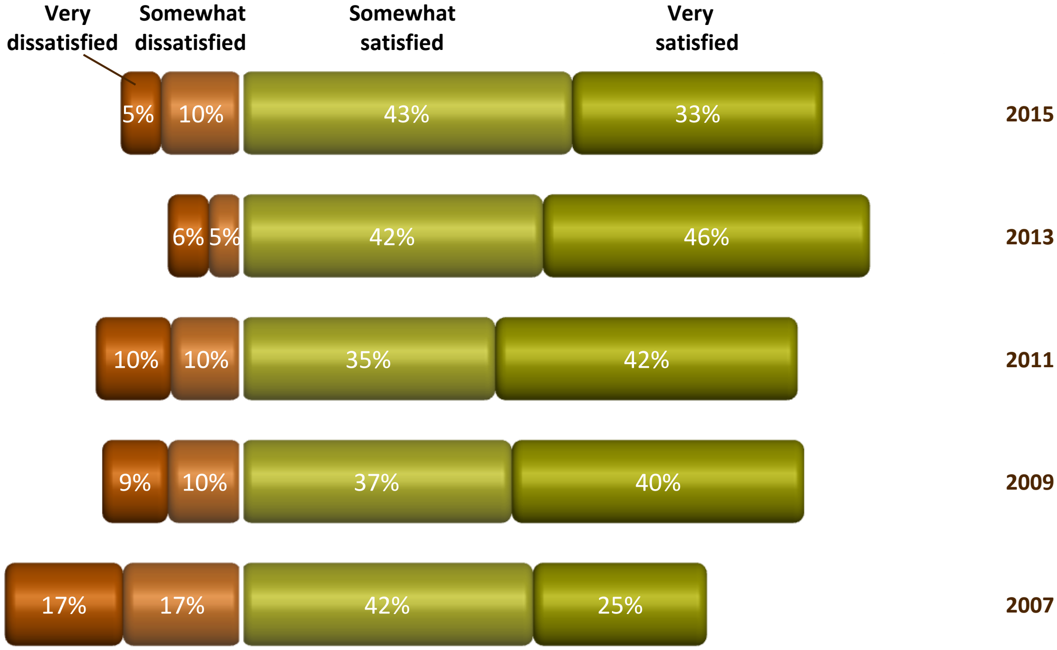
| Nature of Hydro One Inquiries | 2015 | 2013 | 2011 | 2009 |
|---|---|---|---|---|
| About your bill | 26% | 19% | 24% | 20% |
| Because power was out | 9% | 11% | 15% | 15% |
| For information | 17% | 12% | 13% | 18% |
| Another reason | 13% | 9% | 10% | 9% |
| Have not called Hydro One in past year | 58% | 62% | 54% | 57% |
| Don't recall | 0% | 1% | 2% | 2% |

Percentages do not total 100% because customers were permitted more than one response

### *Hydro One Remotes' Handling of Customer Contact*

Customer satisfaction with how Hydro One Remotes handled their contact dropped 12 points to 76% after 2013's record high of 88%, but is still the second highest satisfaction rating since tracking began. Those who said they were very satisfied with their contact with Hydro One is down 13 points to 33%, its lowest level since 2007 (25%).

Chart 7: **Satisfaction with Problem Resolution**




- Respondents whose primary heat source is electricity are most likely to be very satisfied with Hydro One Remotes handling of their problem (45% of 29N) and propane users are least satisfied (0% of 3N), compared to respondents overall (32%). When very satisfied and somewhat satisfied responses are combined, those who heat with wood are most satisfied (83% of 118N) and oil users are least satisfied (50% of 26N), compared to respondents overall (75%).

## Factors Driving Perceptions of Hydro One & Satisfaction with Service

The research tested customers' agreement with a number of statements related to customer service, to explore customers' experiences and perceptions in key service areas. Hydro One Remote Communities scored best at **dealing with emergencies** (80% agree overall) and **staff being polite and friendly** (75%). Customers were less likely to agree that **when they call the Hydro One office someone usually answers quickly,** though a majority still agreed (62%).

Agreement with each of these statements dropped when compared to results in 2013 and, in the case of the first two statements, to their lowest levels since tracking began. Overall agreement with the third statement dropped three points to 62%, one point higher than its lowest level in 2011 (61%).

Table 5: **Perceptions in Key Service Areas**

| Statement | 2015 | 2013 | 2011 | 2009 |
|---|---|---|---|---|
| Hydro One usually deals with emergencies, such as when as the power is out, in a reasonable amount of time. | 80%* (15%) | 88% (18%) | 85% (20%) | 86% (18%) |
| When I call the Hydro One office, the staff are polite and friendly to me. | 75% (17%) | 80% (20%) | 80% (18%) | 80% (20%) |
| When I call the Hydro One office someone usually answers the phone quickly. | 62% (11%) | 65% (11%) | 61% (12%) | 68% (12%) |

*Unbracketed percentages combine agree and strongly agree responses, bracketed percentages are strongly agree responses only.

Percentages do not total 100% because those who were unsure are not included.

- The view that Hydro One staff are polite and friendly is highest in Gull Bay (100% of 9N, including 33% strongly agree) and lowest in Webequie (43% of 7N, including 14% strongly).
- This perception is also highest among those who are generally very satisfied with Hydro One Remotes (39% of 41N), compared to customers overall (17%).

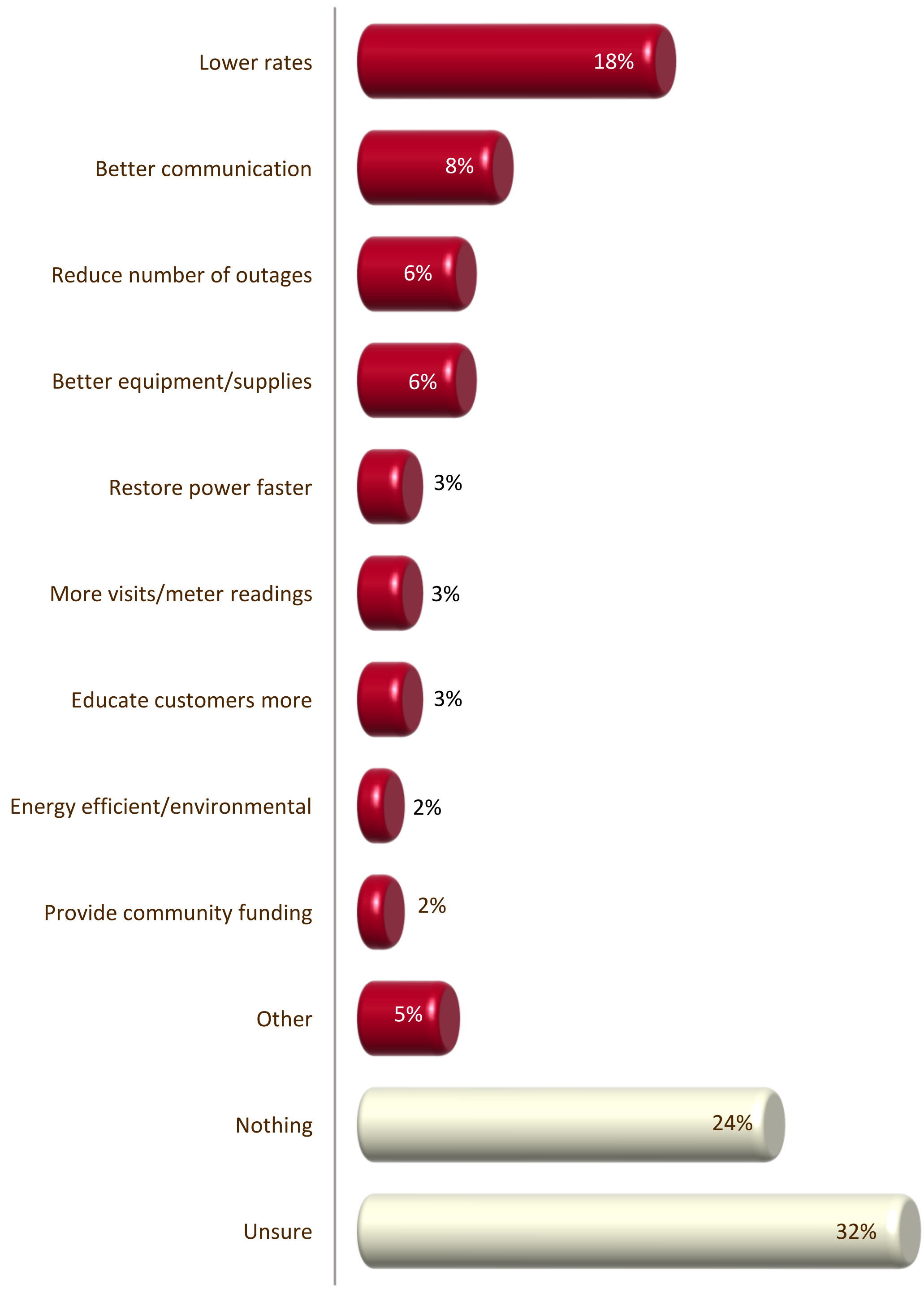
## What Hydro One Can Do to Improve Service to Customers

When asked what Hydro One Remotes could be doing to improve service to customers, the most frequently mentioned improvement is lowering rates (18%).

The desire for better communications was mentioned by 8% of respondents, while reducing the number of outages and using better equipment and supplies were each mentioned by 6% of respondents.

When respondents offered an answer that could not be classified on the list of response categories provided to interviewers, their answers were recorded verbatim by the interviewer (5%). These verbatim responses can be found in Appendix A.

Chart 8: **Ways to Improve Service**

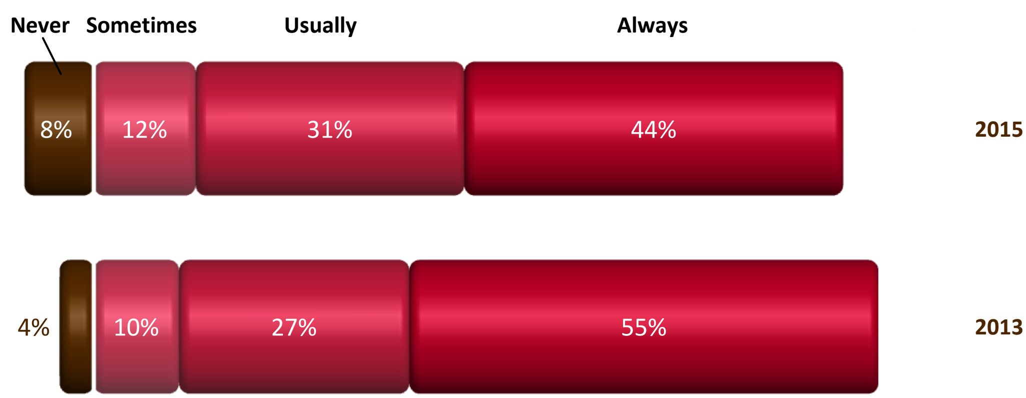


## Informing Customers of Planned Outages

The perception that Hydro One informs customers and communities when power will be turned off for scheduled maintenance and service improvements has dropped slightly since 2013. Those who feel Hydro One always informs them lost 11 points to 44%, while those who feel they do so usually is up 4 points to 31%, and those who say they are informed sometimes is up 2 points to 12%.

Those who feel Hydro One never informs customers about planned outages doubled to 8% since 2013.

Chart 9: **Informing Customers**

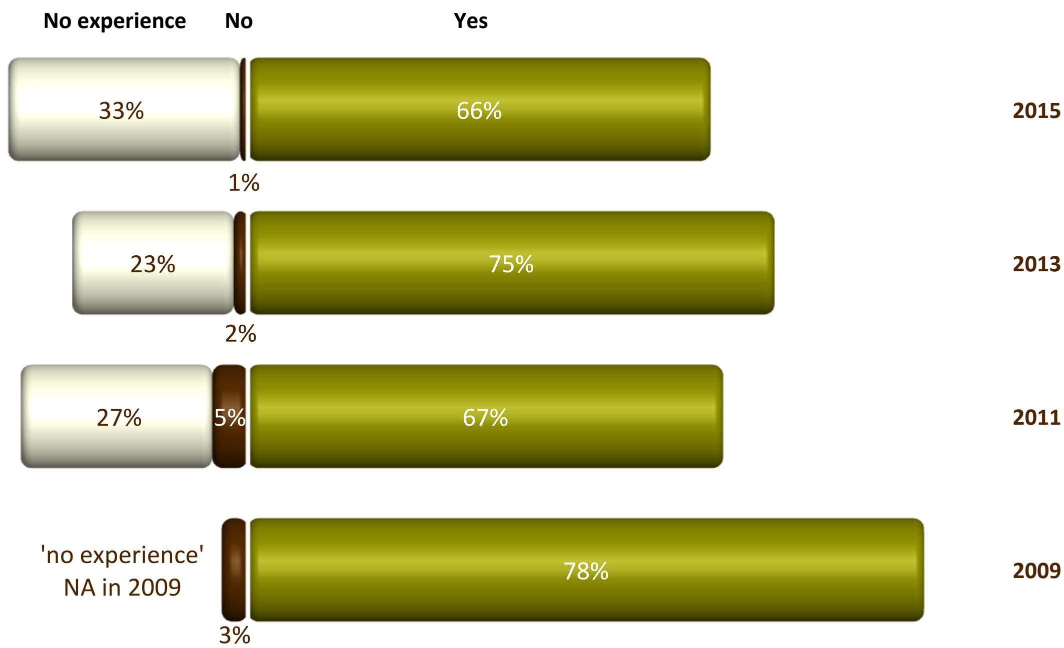



- The perception that Hydro One Remotes always lets its customers know about planned outages is highest among those whose primary heat source is electricity (52% of 29N) and lowest among propane users (10% of 10N).
- Those who are very satisfied with Hydro One Remotes generally are more likely to hold the view that Hydro One lets its customers know about planned outages (71% 41N), compared to respondents overall (44%).

## Staff is Polite & Helpful

Two thirds of customers indicated that Hydro One Remote Communities staff is generally polite and helpful when they come to their community to do things such as bring the electricity back on (66%), down 9 points since 2013 and at its lowest level since tracking began on this question in 2009. Just 1% of customers said staff are not polite and helpful, an improvement over 2013 (2%), 2011 (5%) and 2009 (3%). One in three customers said they do not have enough experience to answer this question, up 10 points since 2013 and above 2011 numbers (27%).

Chart 10: **Staff Polite & Helpful**

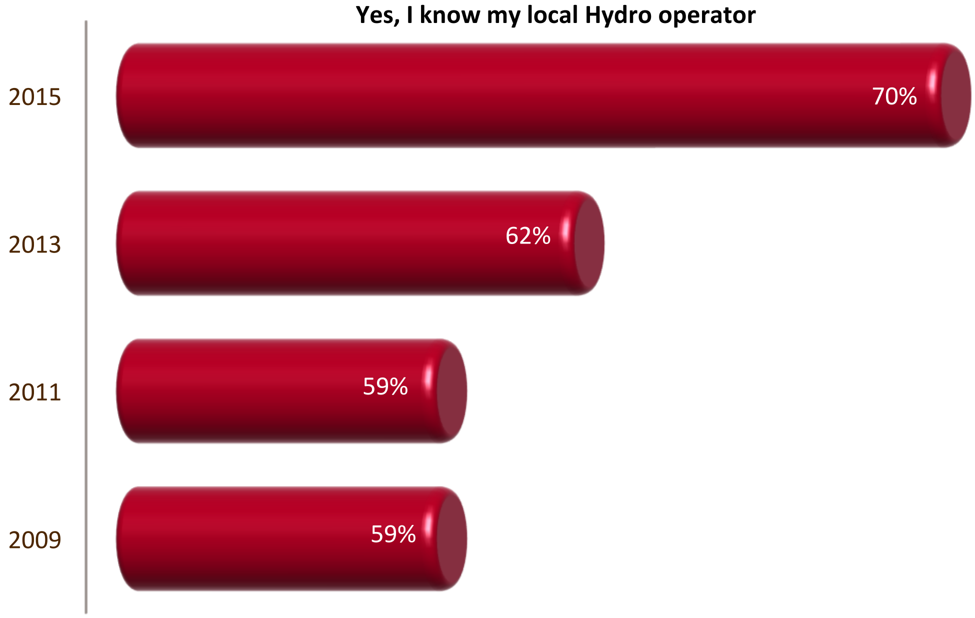



## Awareness of Local Staff

### *Local Operators*

Awareness of who the local Hydro One operator is steadily rising, up 8 points to 70% in this wave of research, while 30% do not know the local operator, down 7 points. Awareness is also higher than 2011 and 2009 when 59% said they knew who their local Hydro One operator was.

Chart 11: **Awareness of Local Operators**

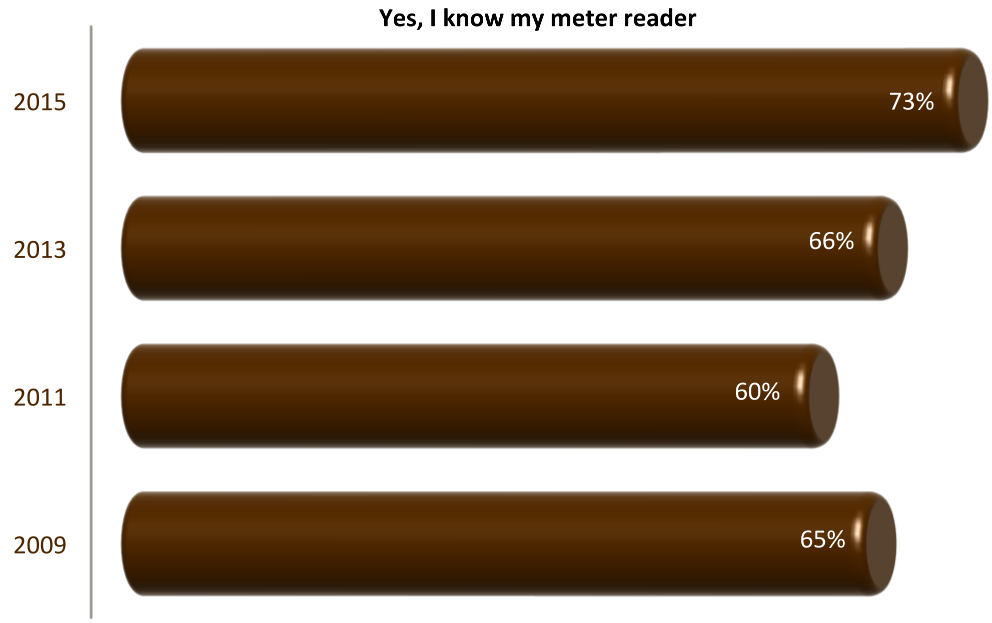



- Those most likely to know their Hydro operator live in: Bearskin Lake (9N), Kingfisher Lake (7N), Lansdowne House/Neskantaga (6N), Marten Falls/Ogoki (2N) and Wapekeke/Angling Lake (6N) (each 100%).
- Those least likely to know their Hydro operator live in: Hillsport/Mobert (0% of 4N) and Armstong/Whitesands/Colins (33% of 3N).
- Those who heat with wood are most likely to know their local Hydro operator (79% of 118N) and those who heat with propane are least likely to (40% of 10N). Those who heat primarily with electricity are less likely to know their local Hydro operator (55% of 29N) than respondents overall (70%).

### *Meter Readers*

More than seven in ten respondents know who their meter reader is (73%), up 6 points from 2013 and at its highest level over four waves of tracking. One in three customers surveyed admitted they do not know their local meter reader (27%), down 7 points.

Chart 12: **Awareness of Hydro Meter Readers**

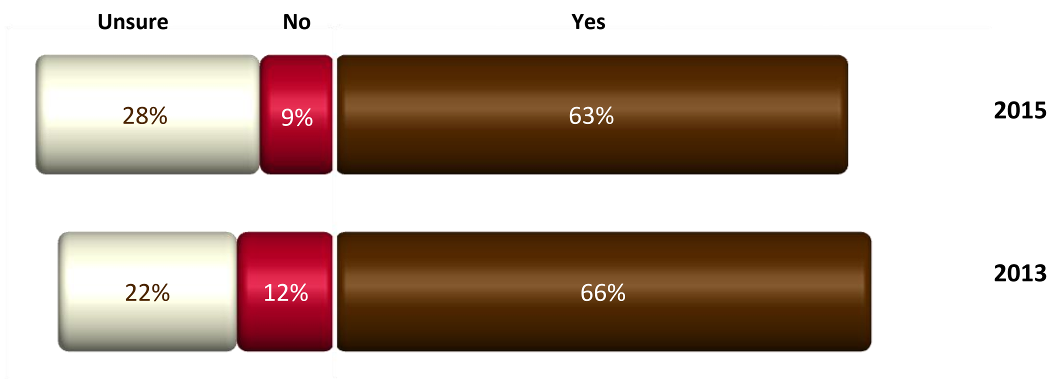



- The communities most likely to know their meter reader are Fort Severn (5N) Marten Falls/Ogoki (2N), Oba (2N), Sultan (14N) and Wapekeka/Angling Lake (6N), (all 100%).
- The communities least likely to know their meter reader are Armstrong/Whitesands/Colins (3N), Gull Bay (9N) and Hillsport/Mobert (4N), all 0%).

## Environmental Protection

Fewer than two thirds of respondents said Hydro One takes environmental protection in the community seriously (63%), down 3 points since 2013. About one in ten said Hydro One does not take it seriously (9%), also down 3 points since the last wave of research. More than one quarter of respondents were unsure (28%), up 6 points.

Chart 13: **Does Hydro Take Local Environmental Protection Seriously?**

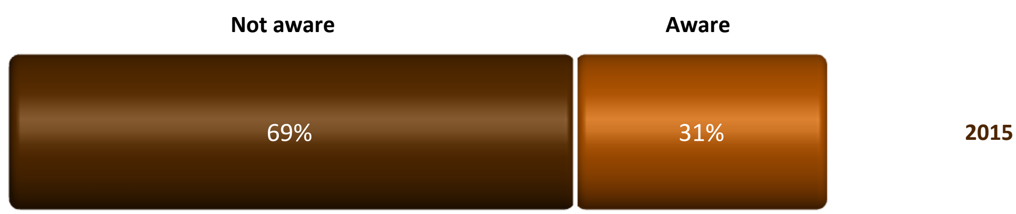



## Energy Efficiency Incentives

### *Appliance Rebates*

Asked if they are aware that Hydro One will provide them with mail-in rebates of up to $200 when they buy energy efficient appliances, three in ten said they know about this program (31%), but a majority of customers said they did not (69%).

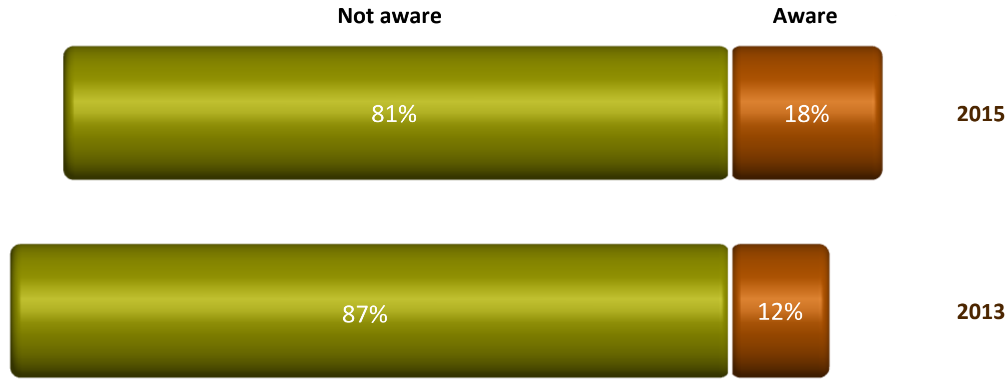
Chart 14: **Mail-In Appliance Rebates**




### *LEAP*

Hydro One operates a program called LEAP, which gives low-income residential customers up to $600 a year to help them pay their electricity bill to avoid disruptions to their service. Awareness of this program is up 6 points to 18% since 2013. Four of five respondents were not aware of the program (81%).

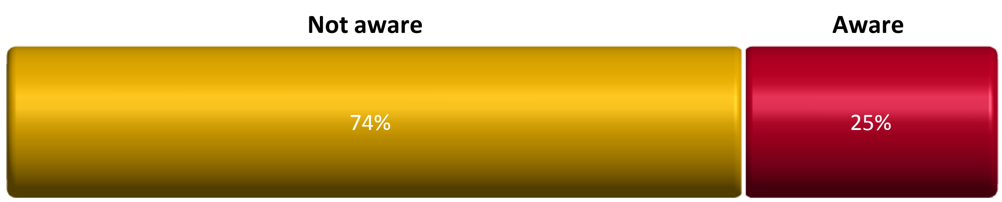
Chart 15: **LEAP Program**




### *Selling Electricity Back to Hydro*

One in four respondents were aware that communities like theirs can generate renewable electricity through solar, wind or small hydro water projects and sell it back to Hydro One Remotes (25%), while almost three times as many were not aware of this opportunity (74%).

Chart 16: **Selling Electricity Back to Hydro**

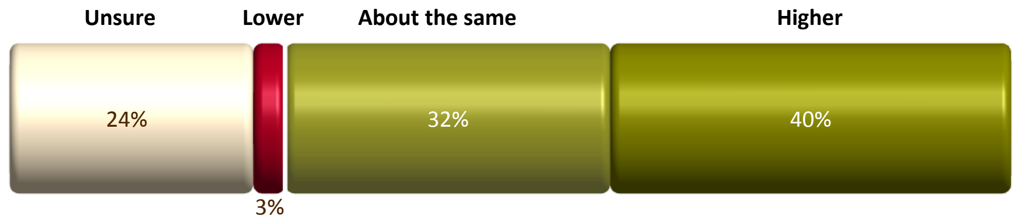



## Hydro Rates

### *Compared to Other Ontarians*

A majority of Hydro One Remotes customers believe their Hydro rates are either the same as the rest of Ontario (32%) or higher (40%), while one in four are unsure (24%). Just 3% of customers believe their rates are lower.

Chart 17: **Hydro Rates Compared to Other Ontarians**

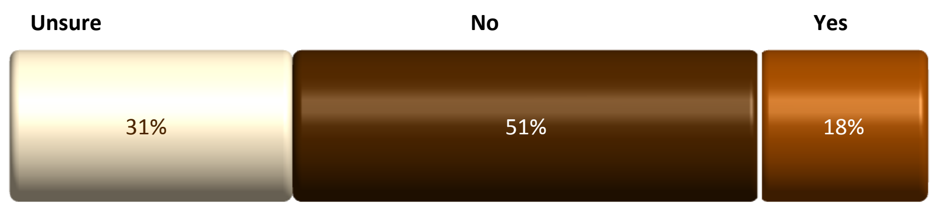



- Residents who are very satisfied are less likely to think their rates are higher than the rest of Ontario (20% of 41N), compared to respondents overall (40%).

### *Willing to Pay More?*

A majority of Hydro One Remotes customers are not willing to pay more for electricity generated from renewable sources such as water, solar or wind (51%), while fewer than one in five said they would be (18%). Three in ten are unsure (31%).

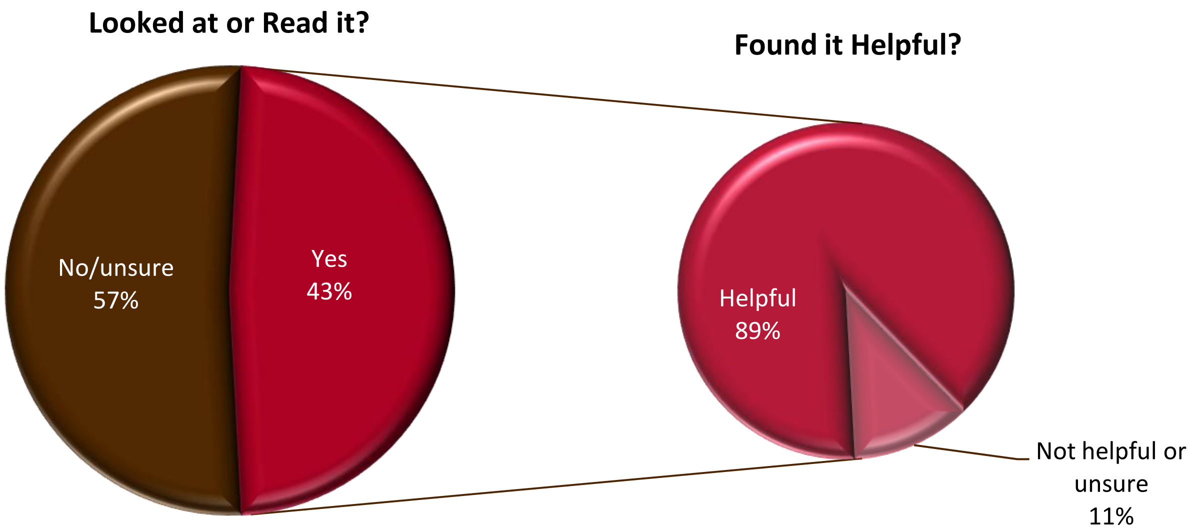
Chart 18: **Willing to Pay More?**




## Communication Materials

Survey respondents were asked if they look at *Connected*, the newsletter Hydro One Remotes mails to them. More than four in ten respondents said they look at or read the newsletter (43%) and, of these (N=79), nine in ten said they find the information helpful or interesting (89%).

Chart 19: ***Connected*, Newsletter from Hydro One Remotes**



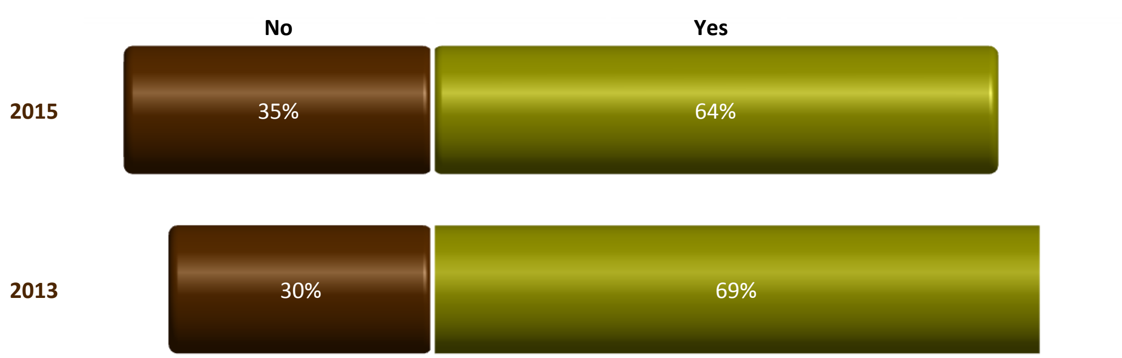

- Residents who had contacted Hydro One Remotes in the past year are more likely to find the newsletter helpful or interesting (100% of 38N), compared to those who did not contact Hydro One (78% of 41N).

## Internet Access & Usage

### *Internet Access*

Approximately two thirds of customers said they have regular access to the internet (64%), down 5 points from 2013, while a third do not (35%).

Chart 20: **Internet Access**



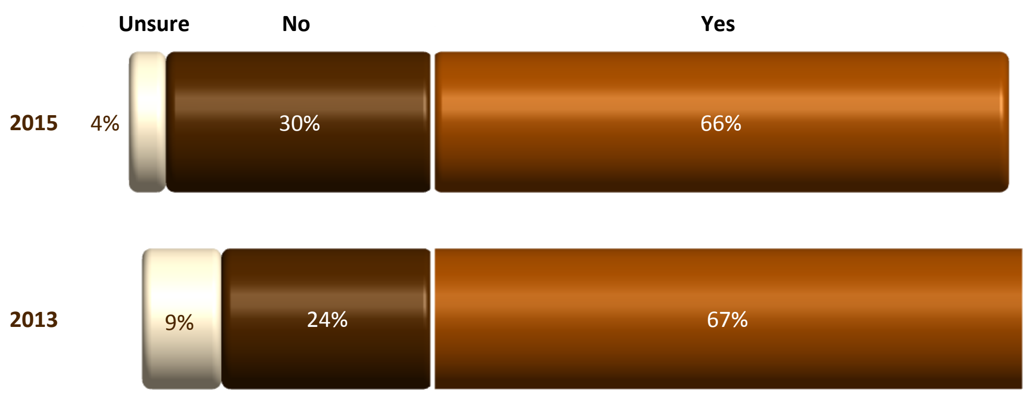
- Internet access is more than twice as high among 18 to 34 year olds (92% of 39N) than those 55+ (44% of 81N).

### *Internet Usage*

Among those customers with regular access (N=119), two thirds think they would be likely to use the internet to get information from Hydro One such as their electricity bill and information about planned power outages (66%). This is similar to 2013 results.

One in four said they would not use the internet to access this type of information (30%) while 4% could not say whether they would or would not use it or said it would depend.

Chart 21: **Internet Usage**




- Businesses (100% of 5N) and those who contacted Hydro One Remotes in the past year (80% of 50N) are more likely to use the internet to get information from Hydro One Remotes, compared to customers overall (66%).

# APPENDIX A

**Q26** What are the most important things that Hydro One Remotes, the company that provides you with electricity, should be doing to improve service to you?

| Community | Ways to Improve Service |
|---|---|
| Armstrong/ Whitesands/Colins | Seasonal rates are too high. |
| Bearskin Lake | Continue advertising their advice to save hydro.<br><br>Give energy conservation stuff like light bulbs. |
| Big Trout Lake/KI | Send surveys to the customers of First Nations.<br><br>Make themselves visible in the community.<br><br>The generator we have is at full capacity. It would be good if they could work on that.<br><br>Have fewer power outages.<br><br>It seems as if, every time they come out to our community when the power goes out, we notice an increase in our hydro bill the next billing cycle, and in the winter it's ridiculously high. |
| Biscotasing | Send out the papers about rebates.<br><br>Stop the power outages.<br><br>Increase reliability.<br><br>Move from the diesel generators and pursue the alternative energy sources including nuclear power generating stations.<br><br>When a brownout occurs, it would be helpful for them to explain why it happened. It would also be helpful to have some information about surges during brownout for the telephone and fridge. Improve communications by phone and cell phone.<br><br>Put in bigger diesels. There are always power outages on long weekends. Sometimes the letters don't correspond with the situation we have here. Fix problems instead of using bandaid solutions. |

| Community | Ways to Improve Service |
|---|---|
| Deer Lake | Get my new house hooked up. I have been waiting 3 years.<br><br>Keep the power on.<br><br>Keep it going.<br><br>Fewer outages.<br><br>There are too many bushes around the hydro poles and wires.<br><br>Make another dam.<br><br>Hook up my new house. It was built 4 or 5 years ago and I still have not been hooked up to hydro. |
| Fort Severn | Provide more and proper installment of lights and wiring and a program that will lower the rates. We need accurate, honest meter readers and we should be informed what our meter readings are. We are never informed by the meter reader.<br><br>Give more information sessions and promotional giveaways so we can get more information. Not everyone reads the pamphlets in the mail. It's just like another flyer. |
| Gull Bay | We like to be informed of planned outages. The hydro operator will turn off the power suddenly without notice. We don't know why. Sometimes it will be off about 5 minutes. |
| Hillsport / Mobert | Read the meter the monthly<br><br>Come down here and let us know what is going on, and what we can do to improve our electricity costs and bring down the bill. They are never helpful. |

| Community | Ways to Improve Service |
|---|---|
| Kasabonika Lake/ Kasabonika | Generate more power. There is not enough power in the community. When they put the Christmas lights out we get a blackout.<br><br>Continue maintaining the power and doing what needs to be done.<br><br>Upgrade the power.<br><br>Have seasonal decreased rates in winter time.<br><br>More of the executives should make long-term trips to these areas. I don't think you know how people live in this community. There has to be more exposure to these lifestyles, and that goes for any business selling services in these areas. |
| Kingfisher Lake | Bring a transmission line in instead of a generator.<br><br>Give discounts in remote communities.<br><br>Provide more information how to save power. |
| Lansdowne House/Neskantaga | Be more efficient so I don't live in darkness for even one hour. |
| Marten Falls / Ogoki | Make the power better with fewer outages. |
| Sachigo Lake | Provide lower rates especially during the winter.<br><br>Participate in the grid plan and help First Nations with the distribution of the power throughout the community.<br><br>Keep notifying us with all the information.<br><br>Provide more selection as to what comes into the house. Have an option for underground or overhanging lines. |

| Community | Ways to Improve Service |
|---|---|
| Sultan | We need new hydro poles in town. They were supposed to raise the wires up and they never did.<br><br>I don't believe the debt retirement should be on our bill. Provide this information properly. Notification of scheduled power outages should be advertised better. It affects sump pumps. The time of year that they choose to do the outages we had high waters and they almost flooded my basement. The outage wasn't advertised.<br><br>Get rid of the debt retirement charge and continue the 10% rebate.<br><br>Have someone come in to check the wiring.<br><br>It would be nice to have an online bill.<br><br>Our whole town has to be rewired. It's all 110 wire, and needs to be on 220. It's not sufficient for the winter. You lose a lot of your power between the amp and the house. If they had heavier wire in the towers our bills wouldn't be as high. |
| Sandy Lake | Make sure that there's no outages.<br><br>Talk to customers more often.<br><br>There are a lot of problems with the birds. Crows land on the poles and wires. They get electrocuted and knock out the power.<br><br>Have different options available for hooking up to the grid; or a way you can do it directly and not have to go through the Band. If you're not on the list of those scheduled to receive help you don't get hooked up. It would be great if there was a way you could do it yourself.<br><br>I use telephone banking and Hydro One doesn't have that.<br><br>Upgrade the boxes and wire and hydro lines. This is an old house and the plastic is chipping off the line. The meter guy said that's quite a hazard. The electrical inside the switches need to be upgraded in the old houses.<br><br>They should not increase the hydro rates because we live in a remote community where everything already costs so much. We barely get by as it is. It does hurt a lot of families when they get disconnected a lot. Put increase notices in the newsletter. |

| Community | Ways to Improve Service |
|---|---|
| Sandy Lake *cont'd* | The generator is growing weaker and weaker as more houses get hooked up. Improve the situation so we have service without interruptions e.g. at Christmas time.<br><br>Make sure they always let us know at least one day before, if possible, about power outages.<br><br>Figure out an alternative ways of getting power here. Diesel generated power is too much. Try a dam that won't affect the river too much. Find out more about geothermal heating.<br><br>They should hook us up to the provincial grid. We are fly-in reserve. There's no way to get fuel in except by airplanes and it would certainly benefit people to hook us up to the power grid. We, as residents, end up paying for the costs of the service as well as the high rates, which is why our bills are so high. Maybe twice a year, they force community members to pay up their bills in full or they come into our reserve and cut off people's service. They are not nice people. They just go and do what they want. They come into people's yards and cut them off. The ones that get cut off are the ones who can't afford the high prices. They practically force a gun down our throats and force us. We have no choice. This past February and March we got notice that they were going to come and disconnect houses and this was in the middle of winter. We had a hard winter and they're telling us they're coming here to disconnect houses! I think that's wrong! When the power goes off it affects our school here. We lose our school days. We lose out on school instructional days. It takes a while for Hydro to heat up the big building, it affects the kids and their families. There should be some kind of reward program for us in the fly-in reserve, rebated with some kind of credit towards our bills. I think Hydro One has a monopoly over us. They don't even reward us. Provide some kind of benefit program for paying our hydro bills on time. That would make people pay their bills on time more likely, if they thought they would get some kind of reward. Last year I got a big bill, about $3000, then the next month my bill was down to $600. I called Hydro One and they said they were in the middle of transferring from an old computer system to a new computer system. I wonder what else is fishy about their billing practices. My daughter collects welfare and her bill was about $400 and all of a sudden her bill went up to $3000. |

| Community | Ways to Improve Service |
|---|---|
| Wapekeka/Angling Lake | Have a newsletter or meetings sometimes.<br><br>Get the power back on faster. |
| Webequie | If they come into the community again they should notify the household that they're going to disconnect, because sometimes we have our payments on hand when they're coming into the community.<br><br>Check the hydro lines. Sometimes they can come down in between the hydro poles. Sometimes they hang across the road. They should have a backup system on the airport strip, in case there's an emergency. What if someone gets sick and power is off.<br><br>Come to the community more often, instead of just when there is an emergency. If they are coming to disconnect they should let the house owner know.<br><br>Support road access for remote First Nation communities, if and when the government decides to put it in. |

# Appendix E: 2016 Customer Workshop Presentation

# Hydro One Remote Communities Workshop

# Summary of Discussion

# November 23-24, 2016

# Sioux Lookout, ON          Sunset Inn

Workshop Objective: To provide an open discussion between HORCI served First Nations, HORCI, OEB and INAC in order to plan for connection and improve coordination, communication and community relations.

Participants:

| | |
|---|---|
| Sachigo Lake First Nation | Kingfisher Lake First Nation |
| Bearskin Lake First Nation | Weagamow Lake First Nation |
| Big Trout Lake First Nation | Wunnumin Lake First Nation |
| Kasabonika Lake First Nation | Wapekeka First Nation |

Regrets due to weather: Sandy Lake First Nation, Deer Lake First Nation

Mandy Wirta, INAC
Richard Habinski, Breann Brunton, Windigo
Donna Brunton, Laura Sayers, Shibogama
Franz Seibel, Roopa Rackshit, KO
Richard Chukra, IFNA
Karemer Coulter, Una O'Reiley, Kevin Mann, Ralph, HORCI
OEB

**November 23, 2016 AGENDA**

- Wataynikaneyap Project update
- Local Distribution Companies preparing for connection to transmission
- INAC presentation and discussion
- Hydro One Remote Communities Inc.
  Transmission readiness, connections and construction, joint use, safety, community relations, customer service, collections, rates, regulatory challenges, asset management, upgrading process, reindeer, retrofit and conservation programs, etc.

**Discussion Themes**

1. Backup Generation
2. Environment
3. Affordability, Billing, Rates and Customer Service
4. Housing Connections

5. Safety and Emergency Response
6. Community Relations
7. Access to Conservation and Renewable Programs

**1. Backup Generation**

Community jobs with be affected including contractors and generator operators. There is a concern regarding the reliability of the transmission line. Some buildings have backup generation, but many homes do not have generators. There is value in the generators that the First Nations own. It is difficult to maintain generators if they are not used for some time. Some are old or in disrepair and should not be kept. Any unused equipment and storage tanks should be removed.

*Recommendation: Continue to work together to establish a plan that works for HORCI, INAC and FNs for backup generation. Evaluate the backup generation requirements in each First Nation including which buildings have backup generators. Any new construction of essential service infrastructure needs to include backup generation (school, clinic, water plant).*

**2. Environment**

Sound pollution is an issue from the DGS. There is contamination at the fuel farm and also at sites where backup generators and fuel tanks were stored. Remotes audits and tracks improvements in emissions and contaminants. Remotes burns approximately 17 million liters of fuel each year. Clothes hung outside smell from the generator smoke. Used oil is removed from oil changes. Are old barrels or single walled tanks removed? Is there a plan to remediate DGS sites? Environment is very important to First Nations.

*Recommendation: Develop an environmental plan with the First Nations that includes current HORCI indicators and include any First Nation indicators. Provide annual reporting to the First Nations in order to monitor environmental indicators.*

**3. Affordability, Billing and Customer Service**

Disconnection policies and communication needs to be improved. LEAP and OESP need to be more accessible. There is lots of paperwork that ONWAA can assist with, but many applications are still not processed. Coordination with Ontario Works is essential to reducing the number of disconnections. How will the rates change after transmission? Customer service should be available in OjiCree. There should be a Remote Northern First Nation rate as the costs in remote First Nations are uniquely high. Interest rates on late payments should be reduced. Funding a First Nation liaison would reduce disconnections and late payments.

*Recommendation: Develop Customer Service policy that includes wages for a liaison in the First Nation, create a remote rate, improve accessibility to rebates, improve disconnection communication, include First Nation customers on customer service review committee.*

## 4. OEB Priority Setting

The OEB is asking utilities to work with customers to ensure that the utilities take into account customer priorities in business and investment planning. This discussion is an opportunity to understand what is important. Each participant was given $10 bills to "vote" for what is most important in various areas of Remotes' work program.

| | |
|---|---|
| Community Relations | 18 |
| Affordability | 17 |
| Customer Service | 17 |
| Renewable Energy | 18 |
| Safety | 11 |
| Reliability | 14 |
| Environmental Protection | 26 |

Discussion notes:

Environmental Protection: My grandfather taught me to protect the land as part of my religion and cannot be compromised.

Renewable Energy: Climate change is real. Makes sense to get our energy and other needs from the earth.

Community Relations and Customer Service: HORCI needs to understand what its customers want and their reality. Customer Relations and Customer Service are HORCI's weaknesses. Hydro One is strong technically but its management of its customer base is weak. You aren't in the community. You need to work in partnership with the community.

Electricity is not affordable. People can't afford it.

## 5. Housing Connections

HORCI requires an ESA inspection prior to connection. There is only one ESA inspector for remotes and there are often delays. In order to connect a building, HORCI must complete a housing layout, contractors cannot complete the layout or complete any work for HORCI due to the union. Fees are established based on established rates. Fees can be reduced if work is bundled. ESA may approve a house before its finished and the house can be connected before it is completed in order to provide electricity during construction. In this way power tools and heaters can be run from the house electricity. It is unclear what HORCI's role is regarding electricity between the meter and the DGS. There should be more options for electrical technicians on reserve.

Communication with HORCI can reduce costs of design and installation especially for positioning of the building and mast, subdivisions and community planning. Retrofit programs are available including LED street light retrofit and conservation programs. LDCs require regular maintenance and need to be kept safe. Colocation of internet cables on poles requires a HORCI engineered design. Annual colocation fees are not charged. Cash in full up front is difficult for First Nation cash flow. 50% cash would make things easier with funding. Will the location of transmission connection be at the DGS site?

*Recommendation: Improved communication between HORCI and First Nation infrastructure planning. HORCI to attend housing and public works conferences to improve understanding and communication with HORCI on housing construction and permits. Reduce HORCI layout and engineering fees. Hire more ESA inspectors.*

**6. Safety and Emergency Response**

HORCI operators are trained in house fire disconnection. Heavy equipment operators are not aware of electricity dangers if they hit lines. There is a handbook for emergency responders on how to deal with electricity emergencies. Firefighters and emergency responders and heavy equipment operators need training to deal with electricity emergencies. School visits are available.

*Recommendation: HORCI to provide training in electrical safety at regional conferences. First Nations to invite remote First Nations to provide safety awareness and complete school visits.*

**7. Community Relations**

HORCI staff housing used to be available as hotel overflow for visitors. Can people stay at the staff house? Does HORCI also rent houses or hotel rooms? HORCI provides training for apprentices at confederation college for linesman. HORCI is unionized and hiring follows the union process. What is the status of HORCI service contracts? Is it possible to sell HORCI generators and other equipment when transmission is connected? HORCI will need to prepare to serve seven IPA First Nations by hiring more staff. The disconnection list is sent every month even though disconnections are only twice per year. This improves communication and helps the band to work with customers.

The chief and council have been handling disconnections. It is a big job for council to manage however, the council is able to care for people and need to approve a visit from HORCI. A community liaison position would provide wages for someone to help people with programs, billing, safety and many other aspects of HORCI relations. There are some programs available with HORCI to support community activities, this helps with relations. A good partnership is required in order to deal with restrictions, disconnections, environment and community infrastructure development. Electricity is a treaty right due to the fact that essential services (health, shelter, education, water) require electricity.

*Recommendation: Develop a Community Relations and Engagement Policy that includes HORCI and First Nation roles and responsibilities. Schedule regular communication and engagement visits. Fund a community position to coordinate training, safety, billing, community relations, promoting conservation, etc.*

8. **Access to Conservation and Renewable Programs**

First Nations are developing renewable infrastructure that needs to be supported by HORCI. Other innovative opportunities needs to be considered as well including heat recovery furnace at garage, furnaces that burn used oil and geothermal. First Nations need HORCI to improve its process and partnership for renewables and the Reindeer program. Retrofit, streetlights and other programs need to be more accessible and promoted in the community. Housing retrofits are still the best way to improve efficiency and conservation. Overcrowding makes conservation difficult.

*Recommendation: More engagement when designing conservation and renewable programs so that they are accessible, meaningful and used.*

**November 24, 2016 AGENDA**

- OEB Presentation on remote residential rates
- Break out Discussions

**Discussion Themes**

- Reduce Standard A Rates
- Eliminate transmission delivery charge
- Secure RRRP
- Improve accessibility to rebates
- Create a separate Northern Remote First Nation Rate
- Reduce late payment interest rate
- Improve REINDEER rate
- First Nation cost of living and electricity as a treaty and human right
- Coordination between INAC, HORCI and OEB

**Group 1 Feedback**

- **Drop Standard A rates for remotes:** The current Standard A rate is 97 Cents/kWh for all the Government funded buildings and with grid connection it will drop to 29 Cents/kWh. It was suggested to consider implementing the 29 Cents/kWh now for a smooth transition to grid connections. OEB could help subsidize that.
- **Drop delivery charges:** Delivery charge was for the grid connected communities in the south that they wanted gone. To consider getting rid of monthly charge on bills for the northern First Nations.
- **Subsidies:** To be cautious on the subsidies during discussions with INAC and to ensure that they need to maintain the current Standard A rate subsidy until the grid connection. Funding cannot be reduced or stalled/when they see cost-savings. (When formulas are calculated for operations and maintenance, the Standard A rates are included and built into the subsidy electric component)
- **Other subsidies:** Construction costs for connections (poles etc) are much higher in the North than in the South.
- **Breakdown of the bundle rate:** The true cost of the power for North is to be provided towards customer education. The breakdown will facilitate better understanding of revenue sources, and payments made on specific allocations by home owners. Even though community members pay a subsidized cost, the breakdown could serve the purpose of an educational tool for RRRP and residential rate payers.
- **Customer relations and Customer service**: To enhance, the group suggested to tie into processes and structures through local RRRP workers who are closer to the communities and delivers energy programs. To initiate a customer education process on rates, bills etc, as part of customer education-a community-based approach. The conservation program could also be brought back as a behavioral modification on using less power,

on using technologies that reduces consumption, bills. (H1RC have an application-based…appliance program)

- H1RC in partnership with the community could engage with the rate payers on conservation, consumer education programs besides the bill collections. **More presence:** HORCI and OEB are asked to have more presence in the community.
- **Late payment charge**: 19.5% on an annual basis is too high and the time frame that kicks in is too short with 20 days. To consider with 60 days' time frame and to be tied to borrowing rates/user rate fees and not market-based rates.
- **Application based programs:** Special consideration is to be made for seniors and elders who find it difficult to navigate through the application process. Try to build/tie into some of the activities showed in the bill and maybe make them "automatic" rather than applying for them.
- **Include an "adder" to off-grid renewable projects:** REINDER programs are not enough, there need to be an "adder" to the REINDEER rate, as an incentive. The "adder" should consider the impact of reduction of the standard A rate. The renewable projects could be made more attractive to find capital/funding for the remotes.
- **Community-specific concerns:**
  KIFN: Senior complexes-individual apartments owned by seniors get Hydro bills but there is no funding for common areas.
  Bearskin: 20$% rebate across the board, on everybody's' bills -suggested directing the savings towards employment, childcare, education, lands and resources, restaurant etc.

**Group 2- Feedback on the OEB processes**

- **Electricity rates:** Hydro bill are too high. To consider seasonal rates as lot more electricity is used in the winter. Or, people who don't have woodstoves have higher costs, especially for the elders and seniors. There are cases with high bills and no jobs. To consider percentage reduction of energy bills.
- **Subsidies:** All customers are different. Some have trucked water, and require lots of electricity to run pumps, so, it is not one size fits all when considering subsidies.
- **Power, food, health:** Anecdotal references were made to situations when options is not food versus power with both being essential necessities. Junk food is cheaper which leads to health and medical treatment issues that is cost intensive. Profile of a different family sizes can be acquired from community economic development offices to iron out fairness in payments. Single mothers, grandparents caring for grandchildren, mentally-challenged, and disabled patients who are unable/or shy away from the welfare application process, become dependents on regular families stretching family budgets. There are no resources to bridge the application process.
- **Incentives**: Incentives for reduced energy use.

- **North versus South unfounded perspectives:** Decision-makers from the South have to visit the northern communities to see first-hand, ground realities. The communities in the north have to deal with a lot more situations that the south doesn't face. Also, "Thunder Bay is not north or reflective of the TRUE NORTH". Also, get an understanding of family structures and community way of life.
- **Energy Star Program**: To be made available to everyone and not just for low-income group people. The H1RC program swaps old appliances for Energy Star appliances.
- **Feedback on the H1RC processes**
- **Community relations**-To understand community' expectation on building relations- "H1RC version is different from ours". Mostly council members attend meetings in Thunder Bay and sometimes the information flow is restricted or stalls at that level. Suggestion was made to engage with the communities more through community meetings organized for EVERYONE to attend, open houses, FB, radio etc. Also, forward materials that are easily understood by the community. Sending program promotional/marketing pamphlets with bills doesn't always work.
  People who implement programs like OESP and LEAP need to go to communities, help them with the application process.
- **Housing:** Lack of housing leads to overcrowding that lead to high electricity bills. Eg: North Caribou. Also, with large families, it is very easy to go over the first 1000kwh threshold. To consider up to 2000 kwh. - 89 $ rate should go higher (upto 2000 kwh)
- **Renewable projects:** Community is interested to invest**,** own and run more renewable options.
- **Standard A** rate on band council building and assets needs to be lower. Shouldn't have to wait for grid connection to get lower standard "A" rate. Don't want rates to change or access to RRRP to go away when grid comes in. Need more than just the $20 service charge off and not make it comparable to the delivery charges of the south.
- **Joint process**: Consult with INAC for cost savings on when the grid comes in. And ensuring that any subsidies that come from OEB does not reflect on a reduced cost saving options from INAC.
- **Subsidies**: Should not be something we have to apply for.
  **Additional concerns:**
  Lots of power surges with diesel generation or power goes out for a few seconds. Thus, outages should result in lower bills and should be reflected on the bills.
  Sometimes when they come to communities to do the disconnections, they won't take any cash.
  Disconnect charges add an extra burden and are varying from 65$-165$ that ensues a long wait to be reconnected once the bill is paid.

**Group 3 Feedback**

- **Standard A rate:** There are two rates-one for the First Nations and one for the Municipal. So, the community deals with the individual bills and Municipal/Band type accounts. Rates are high that the Band office have to sometimes pay from other programs. It was suggested that the respective community band offices need to be made aware that with the grid connections, there is a possibility of the reduced/stalling of the INAC funding and subsequent subsidies. This needs clear understanding amongst all of us and we should be on the same page.
- **Understanding realities:** Both, the communities and H1RC want to be treated fairly and so, to approach the system through a holistic lens. There are realities on both sides-to acknowledge and respect. Adding or subtracting services without realizing the ground realities leads to misunderstanding and lack of expectations.
- **Time of Use rates:** Do not want time of use rates as there are unemployed people and energy consumptions to consider. Using the time of use rate will only hurt us.
- **Cost of living:** To take into account the cost of living and all costs including freight as they are significantly higher. Everything costs double in remote Northern Stores even with a subsidized rate.
  Need to help seniors and Elders who cannot keep up with the costs of living. Reference was made of the 700+ OSEP applications that are stuck in the systems process. This is not acceptable when community members rely on these programs. OEB could address the issue with the Ministry of Finance.
  Also single parents, some are too young to apply and get into the system. Grandparents are playing the roles of the parents and have extended responsibilities.
  Welfare is $400/month/person. How much can it be stretched to in a typical size family?
  Need to keep **“entrench”** RRRP and Standard A subsidies on a long-term basis irrespective of change in Governments. To ask the Province to approach INAC.
  Rates cannot go up (increase) with connection to the Provincial grid. If that happens then there is no value in being connected to grid. We cannot burden communities with additional payments-a principal used for guidance with grid connecting.
- **Customer Services:** Place someone in our community that can help with applications/Forms. Also, need help within the communities with arrear management and not just a 1-800 number. To include management of bills.. when trying to decide how to pay all bills-food, fuel or electricity.
  Reliability is a problem ..need someone in the community to keep the lights on. To explore solutions, H1RC need to visit the communities and talk to community members. Or the community can set a program and appoint someone in the community in partnership with H1RC. The group stressed on **education and communication**. Reference was made of initiating financial management skills.
  The group echoed that we are “remote” and have unique set of challenges. All FNs cannot be treated the same. Comparisons between the North and South should not be made. Reference was made with Land-Fill sites as an example.

- **Renewable Energy:** Walk hand in hand in renewable projects.
- **Watay Power:** To have discussions on bills and payments post grid connection. It is important to prepare the community.
- **Conservation:** Stressed on H1RC conservation programs, appliances and light bulbs replacement etc.
  Payments: Payments upfront
- **Back up generation**: A must for any catastrophe for basic services. No compromise on that. To consider portable units by H1RC. It is not only a back-up system, there are financial implications too.
- Quick response time, especially in the winter-someone on standby 24/7. Faster service.

# Appendix F: Request for IESO Comment Letter

BY COURIER

March 3, 2017

Ms. Miriam Heinz
Regulatory Coordinator
Independent Electricity System Operator
120 Adelaide Street West, Suite 1600
Toronto, ON, M5H 1T1

Dear Ms. Heinz:

**Re: Hydro One Remote Communities Inc. – Letter of Comment**

Hydro One Remote Communities Inc. ("Remotes") is preparing to file a Cost of Service ("CoS") rate application for 2018. As part of this application, Remotes will be including a Distribution System Plan ("DSP") which must be accompanied by a letter of comment from the Independent Electricity System Operator ("IESO").

Remotes' application is subject to the Ontario Energy Board's ("OEB") Filing Requirements for Electricity Transmission and Distribution Rate Applications. These requirements (Chapter 5) indicate the OEB expects the IESO comment letter will include:

- the applications it has received from renewable generators through the [Feed-in Tariff] ("FIT") program for connection in the distributor's service area;
- whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DSP are consistent with any Regional Infrastructure Plan.

In regards to the above points and the letter of comment, please note that:

- Remotes' service area is not eligible for the FIT program and, therefore, there are no FIT applications for connection in Remotes' service area;
- Remotes routinely consults with the IESO on various matters as appropriate;
- Each of the communities served by Remotes is electrically isolated and not connected to the bulk transmission system. Therefore co-ordination with other distributors and/or transmitters on implementing REG investments is not necessary.
- The Remote Community Connection Plan is still under development for Remotes' region.

Remotes respectfully requests a letter of comment from the IESO addressing these points, as appropriate, by April 3rd, 2017. If you have any questions, or require additional information, please contact our Regulatory Affairs group at Regulatory@HydroOne.com.

Sincerely,

ORIGINAL SIGNED BY KAREN TAYLOR

Karen Taylor
Senior Director, Applications Delivery
Regulatory Affairs

# Appendix G: IESO Comment Letter

# IESO Letter of Comment

# Hydro One Remote Communities Inc.

# Renewable Energy Generation Investments

April 4, 2017

Independent Electricity System Operator

## Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

## Hydro One Remote Communities Inc. – Renewable Energy Generation Investments

On March 3, 2017, the IESO received a letter from Hydro One Remote Communities Inc. ("Remotes") in order to obtain a letter of comment from the IESO pertaining to Renewable Energy Generation Investments Information as part of its 5-year Distribution System Plan. The IESO has the following comments:

The letter contained no REG investments that required the IESO's comment. The IESO acknowledges that communities served by Remotes were/are not eligible for the FIT program, and therefore there is no need for REG Investments or co-ordination with other distributors and/or transmitters on this subject.

With respect to planning, the IESO confirms that Remotes is an active participant to the Remote Community Connection Plan for which the government issued an Order in Council on July 29, 2016, confirming the need for the project to connect 21 remote communities. Remote community connections are underway and supported by the government designating Wataynikaneyap Power as the transmitter for connecting 16 communities and the new line to Pickle Lake. Remotes is working closely with the IESO with respect to the ongoing work required to connect the remaining five remote communities.

The IESO looks forward to working further with Hydro One Remote Communities Inc. on planning for the connection of remote communities, and appreciates the opportunity to provide its letter of comment as required.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.



Independent Electricity System Operator
*1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1*
*t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca*

# Appendix H: Hydro One Remotes Roof Assessment Report

February 13, 2014

John Supinski
Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON  P7E 6G9
(807)474-2808

**RE: 2013155 – DIESEL GENERATOR STATION ROOF ASSESSMENT REPORT & RECOMMENDATIONS (VARIOUS)**

Dear John,

The office of FORM Architecture Engineering was requested by the owner(Hydro One) to review existing roof construction for four(4) of their diesel generator stations within various remote communities of northern Ontario and to provide feedback to Hydro One on the condition of said roof construction, along with recommendations for future use. This review was requested to determine what, if any, capacity remained within the existing roof structure to accommodate an increase in thermal performance in order to alleviate persistent ice formation along the roof edges. The four(4) diesel generator stations selected by Hydro One for review were in the following communities; Kingfisher Lake, Lansdowne House, Big Trout Lake, and Weagamow First Nation communities.

Contained within the body of this report is a general description of the construction and current condition of each of the four(4) diesel generating station roof structures. The office of FORM Architecture Engineering is to provide recommendations on enhancing the longevity of existing roof construction for the above mentioned locations, as well as potential improvements to thermal performance of the roof structures.

**KINGFISHER LAKE: EXISTING CONDITIONS**

The diesel generator station located in Kingfisher Lake is a manufactured steel building(see photo#1). The exterior dimensions of the building in question are 19.51m(64’-0”)x7.32m(24’-0”).The roof structure consists of steel liner panels acting as the interior ceiling and doubling as the air/vapour barrier. The roof’s thermal layer is comprised of ±280mm(±11”) of fiberglass batt insulation(see photo#2) which equates to an approximate R-value of 40 for dry, uncompressed fiberglass insulation. Roof/ceiling support consists of horizontal steel L51x51x6.4(L2x2x¼”) angles at 2440mm(8’-0”) on-centre. Steel Z-girts run perpendicular to the horizontal structure to support the liner panel ceiling below. To create the sloped roof structure above the ceiling, steel roof panels are supported at the eaves, peak, as well as at the mid-span. Support at the eave is provided by the exterior wall framing, while the mid-span roof panel support is provided at both edges of every panel with what appears to be a vertical 51x51x0.91mm (2x2x20ga.) member(see photo#3) down to the ceiling framing & heavy gauge clips at the roof panels above. Roof panel support at the peak is provided by a pair of heavy gauge ‘Z’ girts, connected side-by-side at their legs and supported at 2440mm(8’-0”) on-centre with vertical L51x51x6.4 (L2x2x¼”) members directly to the horizontal members below(see photos#4-5). It was not feasible to get a direct measurement of the roof slope while onsite due to limited access, but existing slope of this roof appears to be ± 4:12.

The current condition of the existing roof structure appears to be decent. There are no observable signs of condensation issues either within the building or within the attic space. Ventilation is provided at both gable ends by means of a louver grill which is adequate for the main attic section, but a lack of ventilated airspace at the eaves is the likely cause of heat transfer and subsequent ice formation at the roof edge above(see photo#3). Though not apparent during the time of inspection, the owner's representative had expressed concerns over the above mentioned ice formation at the eaves of this building and the ensuing maintenance and safety issues that accompany this ice formation. The owner had previously taken steps to prevent ice formation from sliding from the roof onto the ground by attachment of bent light gauge steel to act as an ice-stop. Measures to-date are only temporary as the ice-stops are connected to light gauge roof panels only and fasteners continually pull out of the light gauge material. The current preventative methodology entails a great deal of maintenance to ensure performance. In addition, continual re-attachment of the temporary ice-stop material provides new penetrations through the roof panels, and compromises the effectiveness of the steel roofing panels to resist the elements(see photo#1).

**LANSDOWNE HOUSE: EXISTING CONDITIONS**

The diesel generator station in Lansdowne House consists of multiple manufactured steel buildings pieced together with various roof elevations and slopes. The portion of the building in question is 15.88m(52'-1")x7.32m(24'-0") with an eave height of 3.60m(11'-10") and a peak height of 4.24m(13'-11"). The slope of the existing roof is 2:12(see photos#6-7 – portions of building with lower roof elevations) though there are subtle differences in roof slope between the two lower elevation portions of roof, as well as the higher elevation roof structure. Roof construction for the 3.66m(12'-0") length addition completed in 1994(identified as Control Room 'A') are similar to that of the Kingfisher Lake Diesel Generator Station in that steel liner panels make up the ceiling and act as the air/vapour barrier, along with a similar construction type for the roof panel supports(see photos#8-10). There are no mid-span supports provided for the roof panels in this addition. It was observed that there is approximately 280mm(11") of fiberglass batt insulation, equating to an approximate R-value of 40 for a dry, uncompressed insulation layer. Roof structure for the 12.19m(40'-0") length section of building immediately adjacent the 1994 addition noted above, also at the lower roof elevation, is constructed from steel stud trusses which appear to be 1.22m(4'-0") on-center with steel 'Z'-girts above to support steel roof panels. The remainder of the existing structure which houses additional diesel generators is in a newer manufactured steel building. This building has a higher eave elevation of 4.37m(14'-4") and is not an area of concern for the owner(refer to photos#6-7).

Within the attic space of the additions, the steel roof panels and structure appear to be sound. There was no observed indications of condensation occurring within the space. There was some minor deterioration visible on the roof panel edges at the exterior of the building along the eaves, though not easily identifiable from any photographs. A major factor influencing this wear is most likely the consistent ice formation and subsequent freeze-thaw cycles that the eave roof panels are subjected to throughout the seasons. At the time of inspection, ice formation had already begun at both eaves of the lower portion of the building. The majority of the ice formation had thus far occurred at the eave side adjacent to the diesel storage tanks(side of building shown in photographs) and within proximity to the diesel generator room. The higher degree of ice formation at this location could be contributed to the diesel generator being the main heat source for this portion of the building. As with the roof at Kingfisher Lake, there is no ventilation allowed at the eave locations within the attic space(refer to photo#9), and as the insulation becomes compressed at the exterior wall, the potential for heat transfer becomes much greater and is the likely cause of ice formation at these locations.

At the time of inspection, there was no visible ice formation on the portion of the building with the higher roof elevation, with ice formation occurring at wall penetrations for exhaust vent locations only.

**BIG TROUT LAKE: EXISTING CONDITIONS**

The diesel generator station in Big Trout Lake appears to be from more than one manufactured steel building. All construction appears similar, as all exterior dimensions are consistent in terms of building width, eave elevation and roof slope. Roof construction spans the entire width of the building and bears upon structure at the exterior walls. Structure for the roof at the Big Trout Lake Generator Station is from fabricated structural steel trusses at 2.44m(8'-0") on-center. Top and bottom chords are comprised of 64mm(2½") square steel HSS sections and 25mm(1") square HSS sections for all vertical web members. Diagonal web members are from 38x10mm(1½"x3/8") steel flat bars(see photos#11-12). As with both the Kingfisher Lake and Lansdowne House Generator Stations, steel liner panels form the ceiling, as well as act as the air/vapour barrier and support the attic insulation. Thermal performance of the roof structure is provided by 280mm(11") of fiberglass batt insulation, which would equate to an approximate R-value of 40 for a dry, uncompressed insulation layer. Steel roof panels are supported at the eave, mid-span and peak by 125mm(5”) steel ‘Z’-girts. Roof slope appears to be at 2:12, though it could not be verified at the time of inspection.

Appearance of both the ceiling and roof panels were fair. There were no visible signs of condensation occurring within the attic space or any other indications that the performance of the steel panels has substantially deteriorated. Ice formation was not observed along the roof eaves during assessment, though the owner’s representative indicated that this station is prone to ice formation along its eaves throughout the winter season. Ventilation for this roof construction is limited to louvers at each gable end, and a lack of airspace at the eaves due to minimal truss heel height and insulation thickness is again a likely cause of heat transfer and subsequent ice formation at the eave locations(refer to photo#13).

**WEAGAMOW: EXISTING CONDITIONS**

Weagamow’s diesel generator station is, once again, a steel manufactured building. The station itself appears to be one building as additional structures tied into the base construction match in dimensions. The building itself is 19.58m(64’-3”) long and 7.32m(24’-0”) wide. Roof construction consists of horizontal steel liner panel acting as the ceiling and as the air/vapour barrier for the roof. Roof framing is from steel stud trusses @ 2.44m(8’-0”) on-center. Truss top and bottom chords are from 152mm(6”) steel stud, with 102mm(4”) steel stud web members. An exact thickness for truss members could not be obtained, though visual inspection indicated a material thickness of 0.91mm(20ga.) steel based upon standardized colour markings visible on steel members(white paint indicates 20ga material – see photo#14). Above steel stud trusses sits 102x3.2mm(4”x1/8”) cold-formed channel purlins at the eaves, mid-span, and peak for which steel roof panels sit atop(see photos#14-15). Visual observation of the attic space revealed that there appeared to be only a single 140mm(5½”) batt of fiberglass insulation throughout the structure, which would approximately be equal to an R-value of 15 for a dry, uncompressed insulation layer.

Ventilation for the entire attic space is from louver grills at each gable end of the structure and is most likely insufficient for the volume of attic space. In addition, there is no air space at the exterior wall locations due to insufficient heel height on the roof trusses(refer to photo#16). At the time of inspection, exterior temperatures were -27°C, though it was noticeably warmer inside the attic space which would indicate significant heat loss from the interior space as was also noticed by the significantly lower amount of snow build-up on the main roof as compared to the fuel line tray immediately adjacent(see photo#17). Though it is not readily apparent from photographs taken while FORM was onsite, photographs supplied by the owner’s representatives indicate that roof panels are beginning to show signs of deterioration on the exterior(see photo#18 – some signs of finish deterioration seen).

**RECOMMENDATIONS:**

A number of factors need to be considered in determining an effective recommendation for the above four(4) diesel generator stations roof maintenance procedures.

The request of the owner is to provide a solution that will minimize, if not eliminate ice formation along the roof eaves as this causes both maintenance as well as health and safety issues throughout the winter months of operation. The owner also requested a minimum R-value for all four(4) roof structures to be, at minimum, a value of 30. In addition, there is a requirement to utilize only non-combustible materials for additional structure and cladding for modifications to any of the facilities (ie. steel stud framing, metal roof panels, aluminum flashing, etc.). As all four(4) locations are situated in remote locations of northern Ontario, with limited transportation access(ie. winter roads for shipping material to site), solution options should make considerations for design optimization and material quantities wherever possible.

From site observations of all four(4) facilities, as well as subsequent review of existing construction, it is the opinion of FORM Architecture Engineering that ice formation on all four diesel generator stations is largely the result of a lack of tempered air space directly above the existing roof insulation layer at eave locations. This lack of tempered air space at eave locations facilitates thermal bridging and subsequent heat loss directly to the metal roof panels above. Any snow present at these locations proceeds to melt and migrate down to the roof edge. Once melted snow reaches a point of the façade where exterior surfaces are below the freezing point, and in combination with outside air temperatures being below freezing, water will re-solidify as ice. This process will continue throughout the winter months provided that snow accumulates upon the roof of the structure and there is heat generation from within. Additionally, in the case of the Weagamow diesel generator station, insufficient insulation provided throughout the roof assembly further contributes to the heat loss and eventual ice formation(as described above) at the eave locations.

In order to expedite the process of remediation, minimize cost impacts to the owner, and based upon assessment of the existing roof structure, the following are recommendations to minimize further ice formation and any damage resulting at the above mentioned generator facilities.

**KINGFISHER LAKE, LANSDOWNE HOUSE & BIG TROUT LAKE GENERATOR STATIONS:**

The three(3) above mentioned facilities have sufficient insulation performance as required by the owner. As such, it is not recommended to proceed with providing additional insulation over and above what is existing in these facilities. Given the lack of ventilation at the eave locations, additional insulation added to the attic space would fail to address the persistence of ice formation along the building eaves.

Through observations on site, and subsequent discussions with a local steel building supplier, it has been determined that the existing roof panels and framing are sufficient to support the minimal additional dead load applied by the application of new roof panels and support framing directly to the existing panels. Discussion with the steel building supplier has indicated that existing steel roof panels are 406mm(16”) wide by 0.61mm (24ga.) thick with 76mm(3”) ridges at their interlock joint. This panel type is consistent for all of the roof additions which are supported at the eaves, peak and mid spans. The steel roof panels for one addition at Lansdowne House in which there are no mid span supports is believed to be from 406mm(16”) wide by 1.9mm(14ga.)thick sheet steel with 102mm(4”) ridges at their interlock.

After assessment of the existing steel roof panels, and steel framing below, it is recommended that for the above three(3) locations, the formation of tempered air space above the existing panels be created. In addition, proper airflow from soffit to the ridge should also be created within the new tempered air space. By providing a tempered space above the existing steel roof, any heat loss which would occur at the eave location must now be transferred through the air space before transmitting heat to the new roof panels above. Creating proper airflow into the air space by allowing fresh cold air in from the soffit and venting out at the ridge, heat transfer through the air space to the new steel roof panels can be significantly reduced.

It is proposed that the owner create an area of tempered air space above existing roof panels by the addition of 152mm(6”) perforated heavy gauge steel ‘Z’ girts running parallel to the ridge at 610mm(2’-0”c/c) and fastened at each existing roof panel ridges with self-tapping sheet metal screws. Soffit venting can be achieved by way of sheet metal framing and perforated sheet at the eave locations, and ridge venting to be provided by a manufactured ridge vent suitable for metal roofing applications. In addition, consideration should be made to incorporate snow-stops along the access side at the Kingfisher Lake generator facility. This station has a steeper pitched roof slope, which increases the potential for snow to fall from the building roof. To accommodate snow-stops, proper sub-framing is to be installed prior to placement of any new roofing panels. Refer to the attached drawing sheet S2 – Big Trout Lake Plans/Elevations/Details(24x36). Details for Kingfisher Lake and Lansdowne House facilities are similar, drawing sheets for these facilities yet to be completed(scheduled for remediation by the owner in 2015).

**WEAGAMOW GENERATOR STATION:**

In addition to the ventilation issue identified for the other three diesel generator stations, Weagamow Generator Station was also observed to have insufficient insulation within the attic space to what is required by the owner. As there is limited space within the existing attic for placement of additional batt insulation, the recommendation of FORM for this structure is as follows: (1) Removal of existing roof panels to facilitate the addition of another 140mm(5½”) fibreglass batt insulation, and (2), similar to the recommendations for the three other stations above, creation of a tempered air space above existing by way of 305mm(12”) perforated heavy gauge steel ‘Z’ girts running parallel to the ridge at 610mm(2’-0”)c/c and fastened to each steel stud roof truss with self-tapping sheet metal screws. Soffit and ridge venting are to be similar to as noted above. Refer to the attached drawing sheet S1 – Weagamow Plans/Elevations/Details(24x36).

**LIMITATIONS:**

Findings and recommendations by FORM Architecture Engineering have been based upon visual assessment and, in part, on information provided by others. Unless noted otherwise, FORM has assumed this information to be correct for the development of the recommendations contained within this report. There is a possibility that unforeseen conditions may be encountered on site during implementation of any or all of the recommendations listed within this document that have not been documented. Should any such unforeseen instance(s) occur, the owner should notify the consultant to determine what, if any impact the discoveries have on the above noted recommendations given.

Please do not hesitate to contact the offices of FORM Architecture Engineering if there are any questions, concerns, or comments about information provided within this report.

Sincerely,

LICENSED PROFESSIONAL ENGINEER
2014/07/17
J. A. PILOT
100101682
PROVINCE OF ONTARIO

Jamie A Pilot, P.Eng.
Associate Partner

Attachments:

- Site Photographs 1-18(10 Pages)
- S1 – Weagamow Plans/Elevations/Details (24x36)
- S2 – Big Trout Lake Plans/Elevations/Details (24x36)

Attachments Not Included:

- S3 – Kingfisher Lake Plans/Elevations/Details (24x36)
- S4 – Lansdowne House Plans/Elevations/Details (24x36)

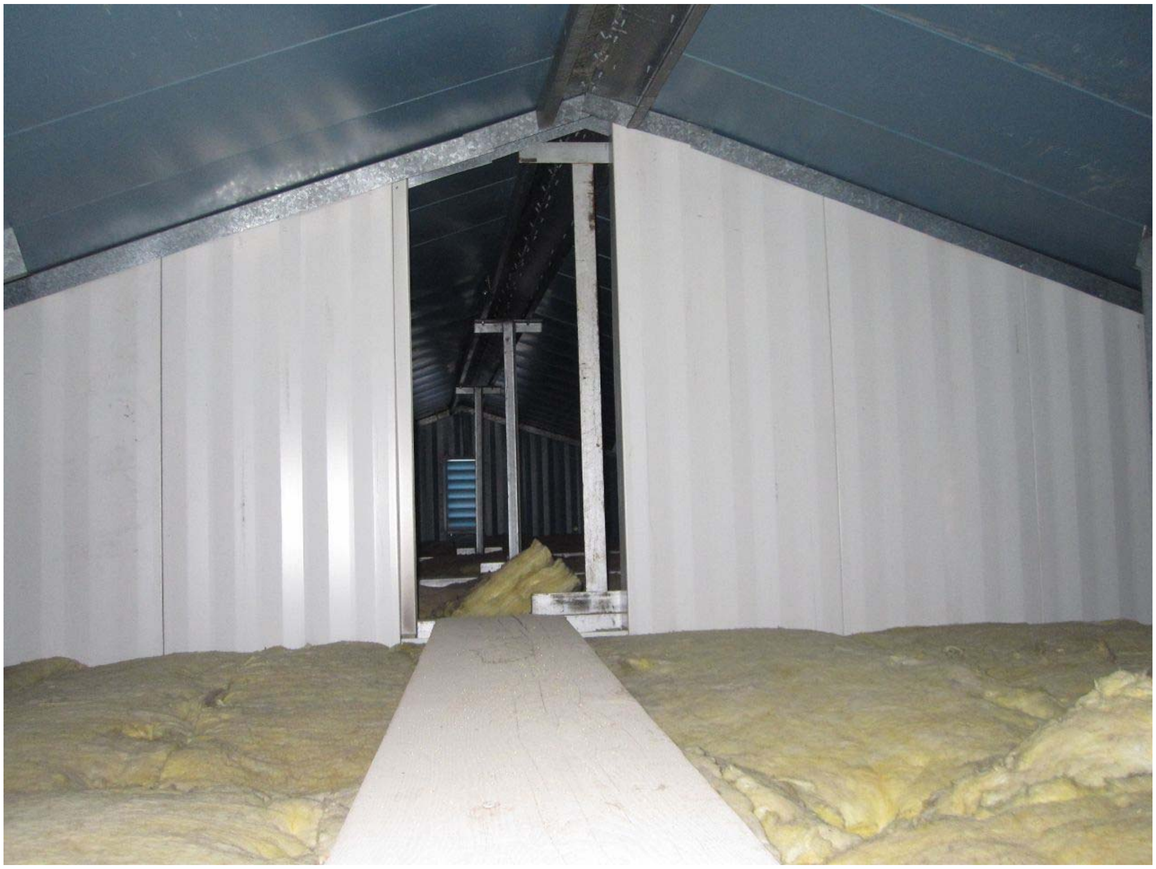
# SITE PHOTOGRAPHS

Photo#1 – Kingfisher Lake Diesel Generator Station (Exterior)

Photo#2 – Existing Roof Insulation Thickness (Kingfisher Lake)


Photo#3 – Roof Panel Mid-Span & Eave Support (Kingfisher Lake)


Photo#4 – Roof Panel Peak Support (Kingfisher Lake)


Photo#5 – Roof Panel Peak Support (Kingfisher Lake)


Photo#6 – Lansdowne House Diesel Generator Station(Exterior)

Photo#7 – Existing Roof Elevation Transition (Lansdowne House)

Photo#8 – Roof Panel Peak Support Framing (Lansdowne House)


Photo#9 – Roof Panel Eave Support/Insulation (Lansdowne House)


Photo#10 – Roof Construction Transition (Lansdowne House)

Photo#11 – Roof Framing (Big Trout Lake)

Photo#12 – Roof Truss Top Chord (Big Trout Lake)

Photo#13 – Roof Panel Support/Insulation (Big Trout Lake)

Photo#14 – Roof Framing (Weagamow)

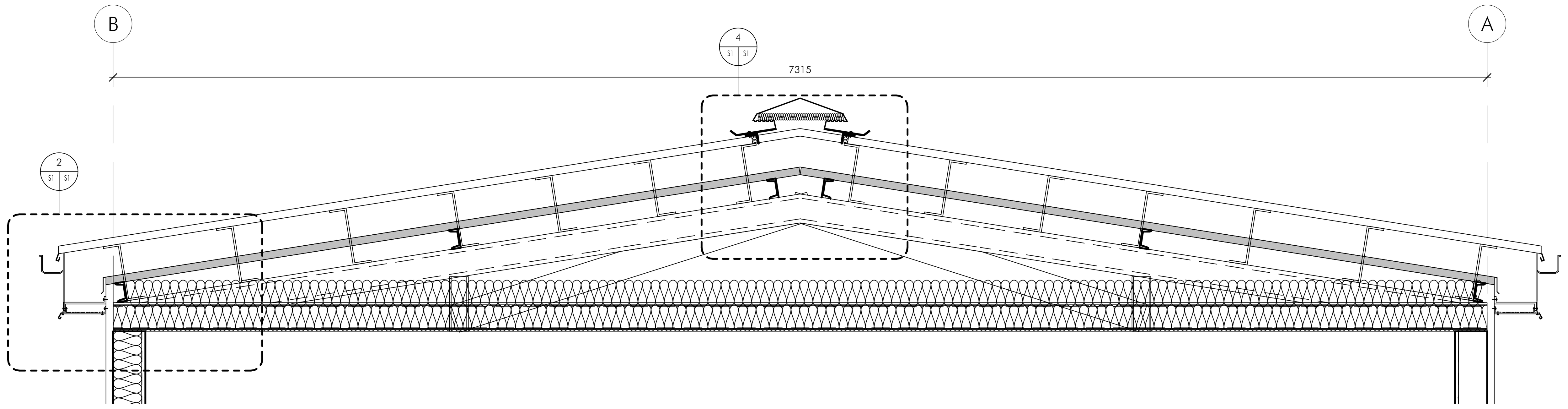

Photo#15 – CFC Purlins (Weagamow)


Photo#16 – Insufficient Air Space (Weagamow)


Photo#16 – Beginnings of Visible Ice Formation (Weagamow)


Photo#17 – Exposed Fuel Line Tray & Visible Heat Loss (Weagamow)


Photo#18 – Visible Heat Loss & Roof Panel Deterioration Signs (Weagamow)

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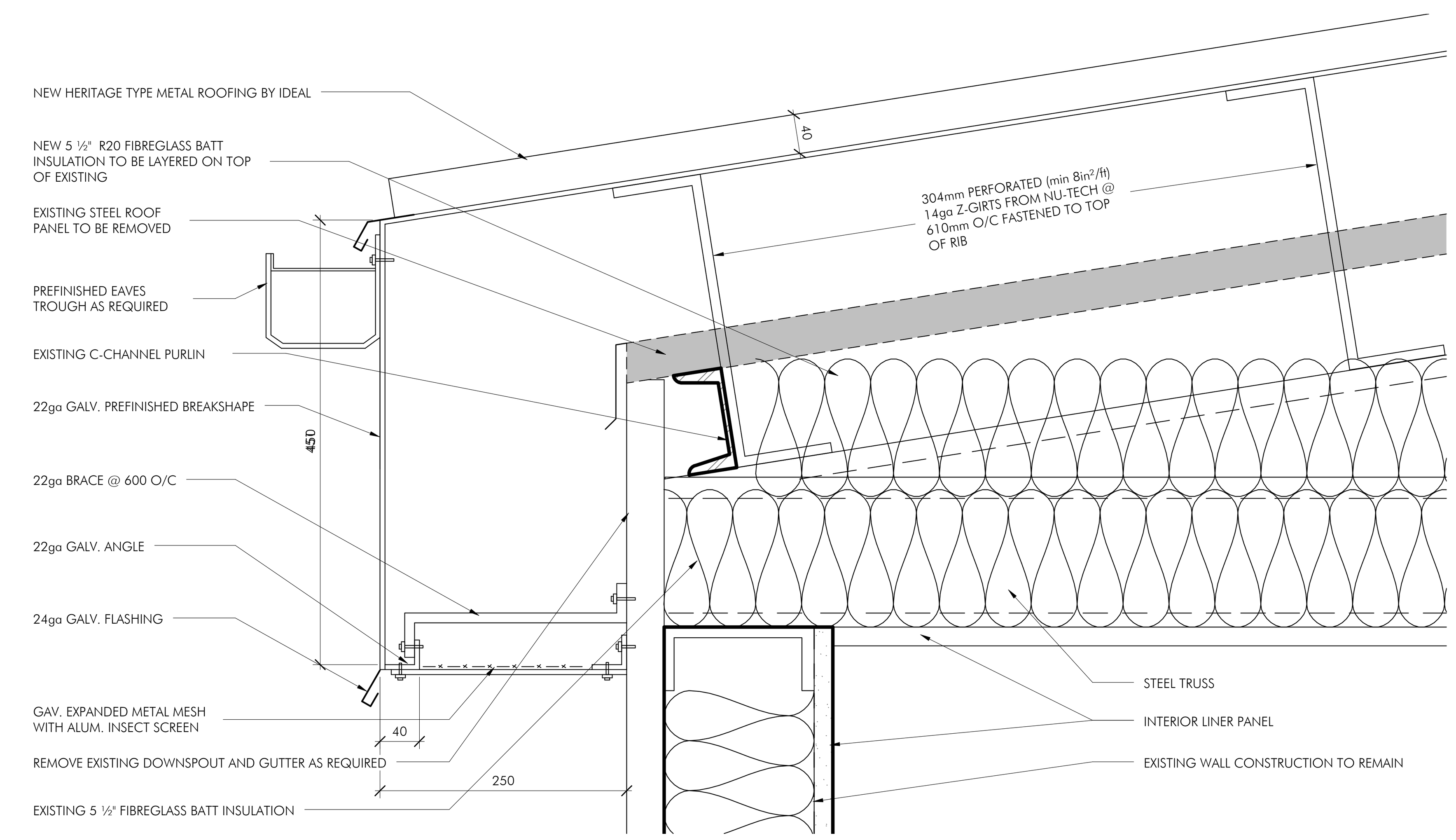


2 CALLOUT AT EAVES
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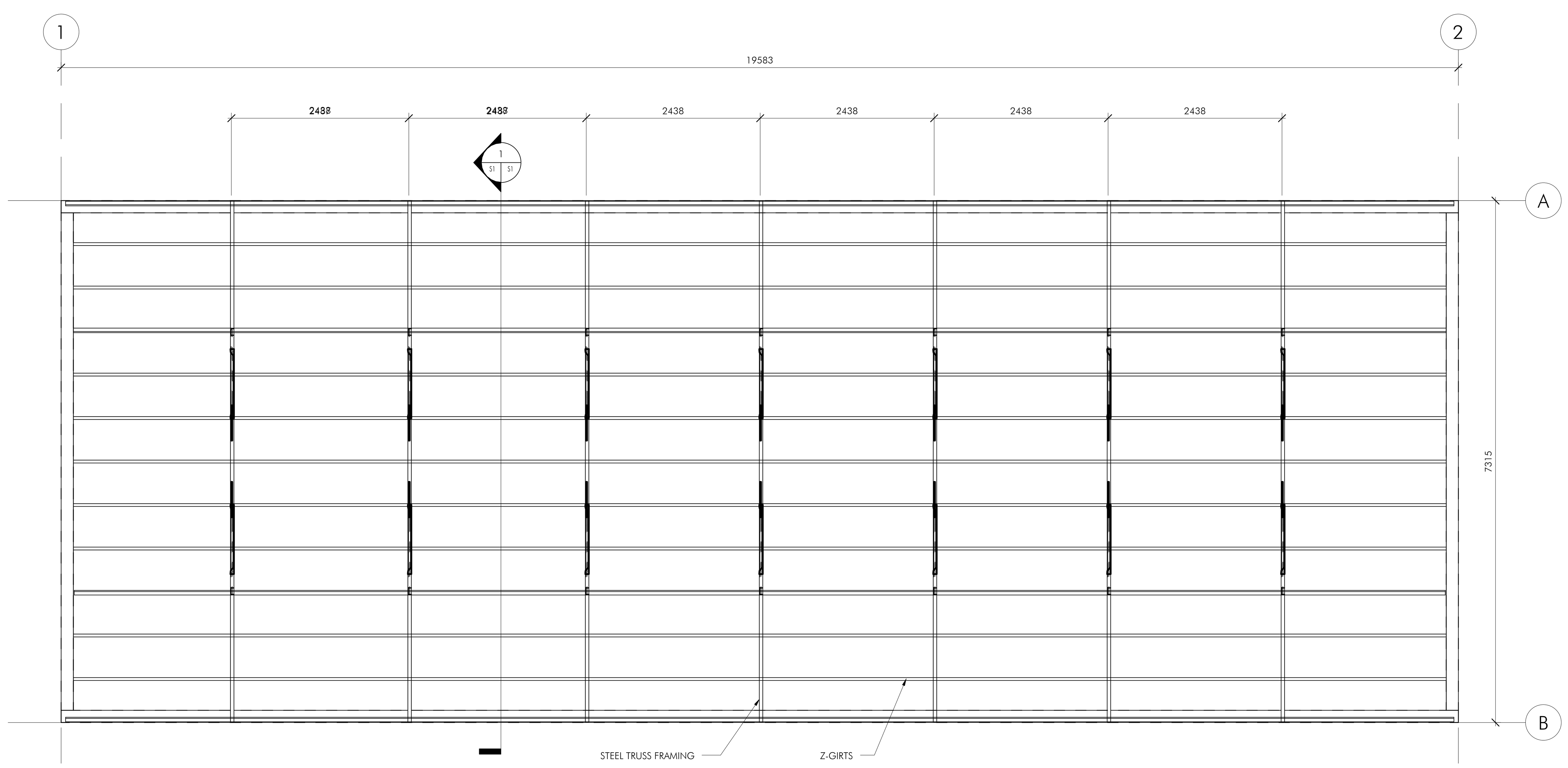


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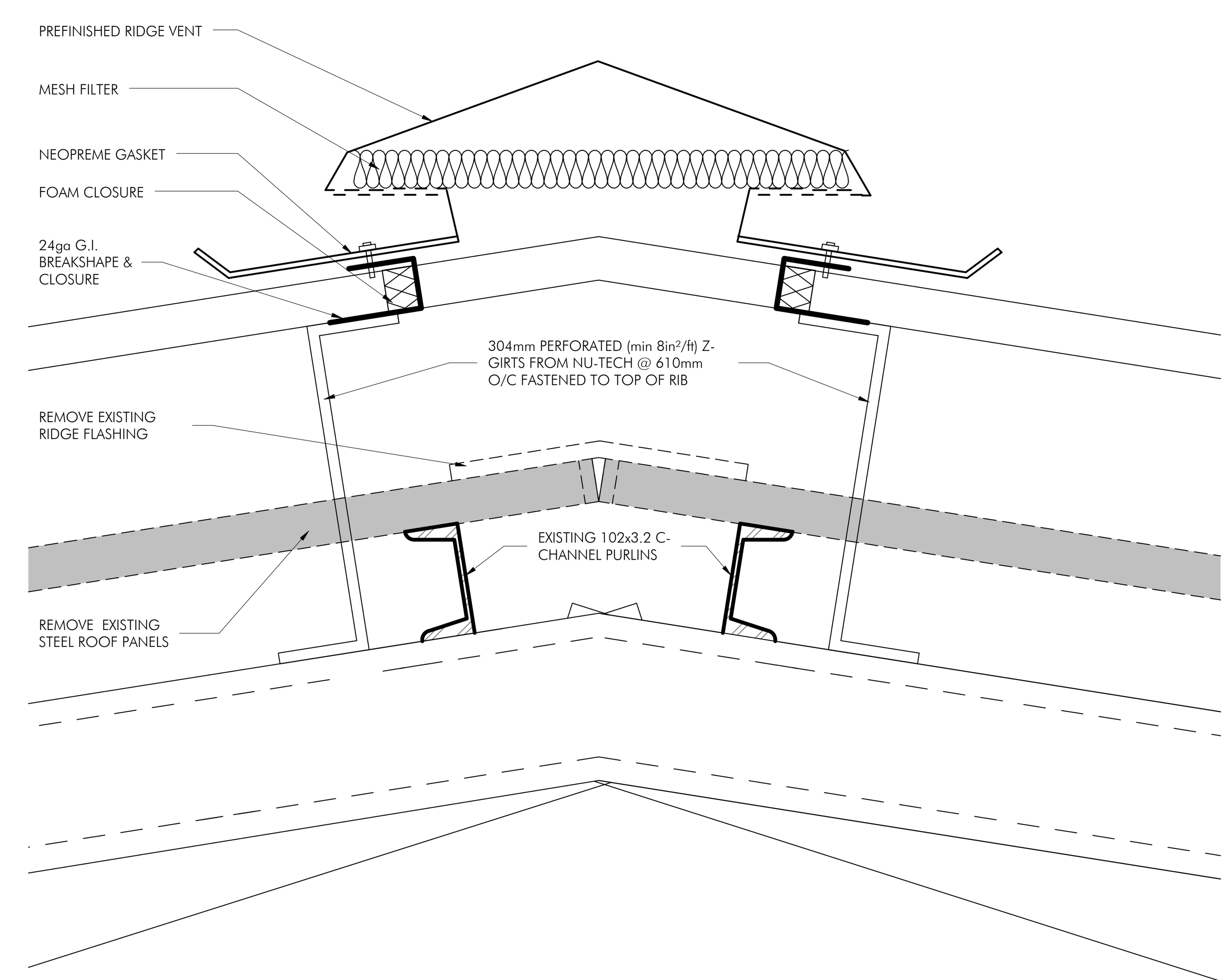


4 CALLOUT AT PEAK
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| REVISION | DATE | DESCRIPTION |

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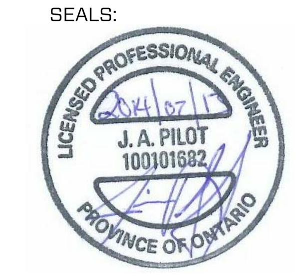


THIS DRAWING IS NOT TO BE USED FOR CONSTRUCTION WITHOUT A PROFESSIONAL SIGNATURE THROUGH THE SEAL.



FORM ARCHITECTURE ENGINEERING
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BETTER PLACES FOR PEOPLE
www.formarchitecture.ca

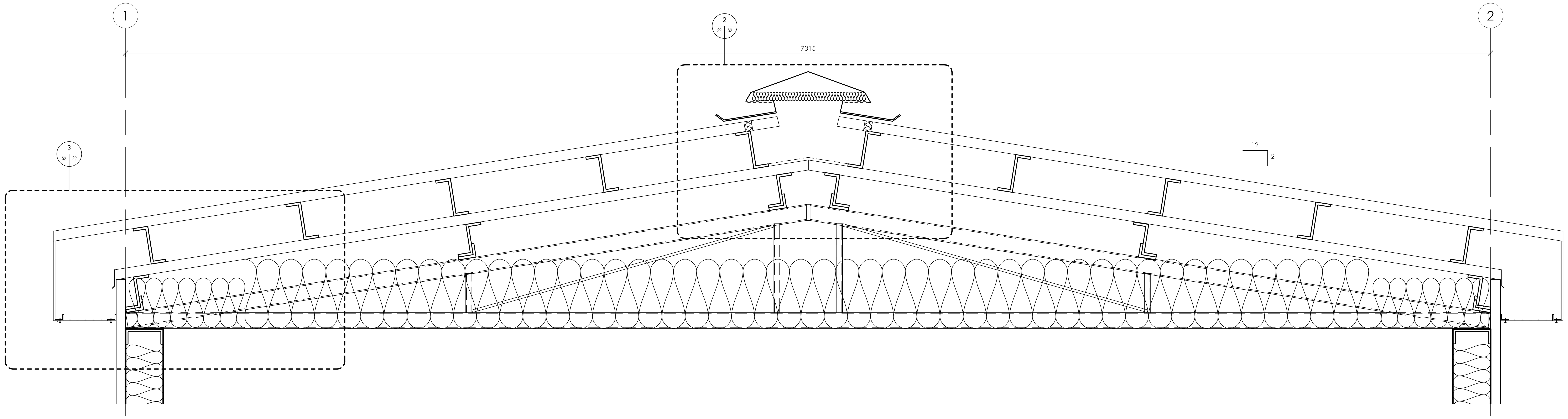
PROJECT NAME:
Hydro One

Remote Roof Upgrades

SHEET TITLE:
WEAGAMOW PLAN & DETAILS

DATE: 14/02/13
DRAWN: KPD
PROJECT: 2013155

# S1



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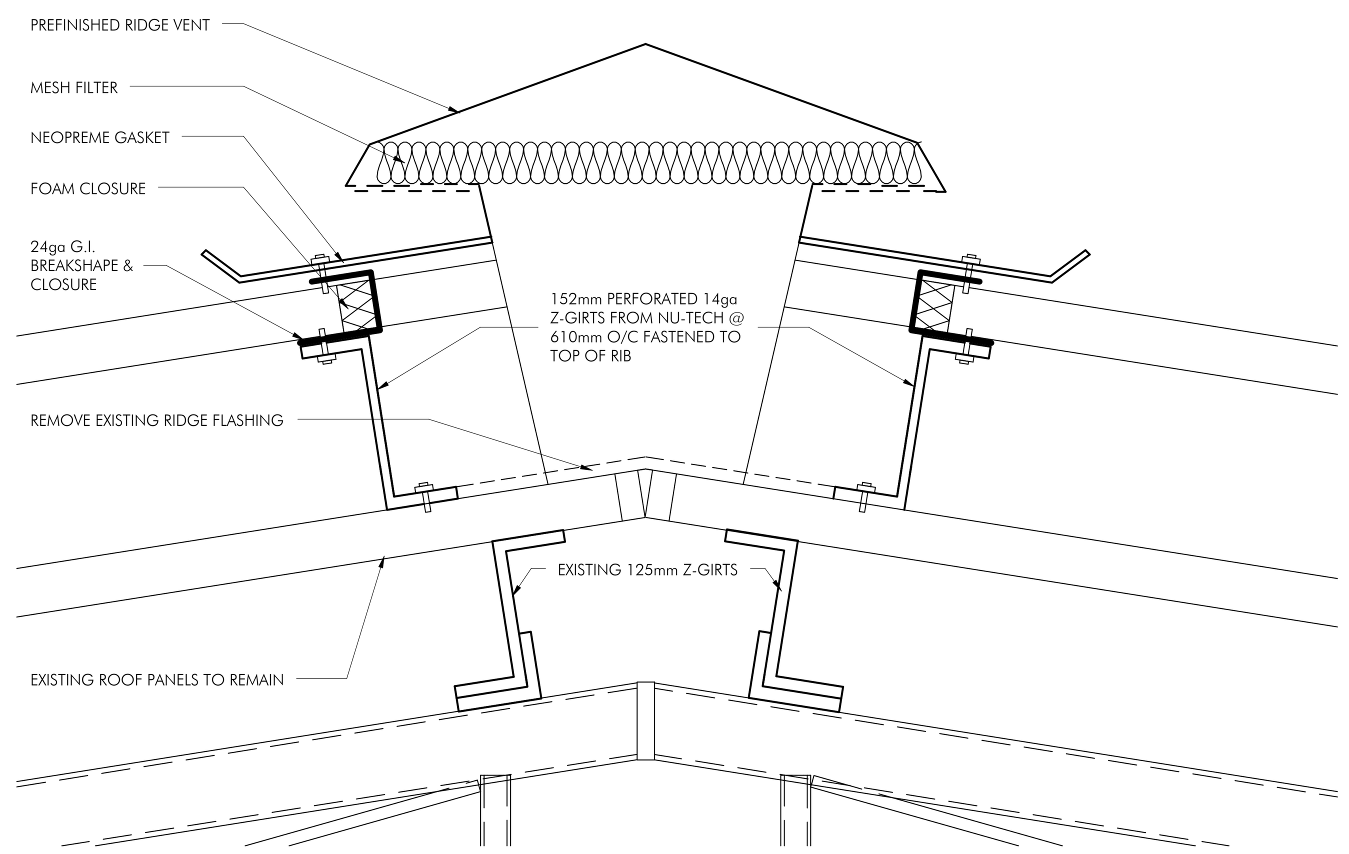


## 2 CALLOUT @ PEAK

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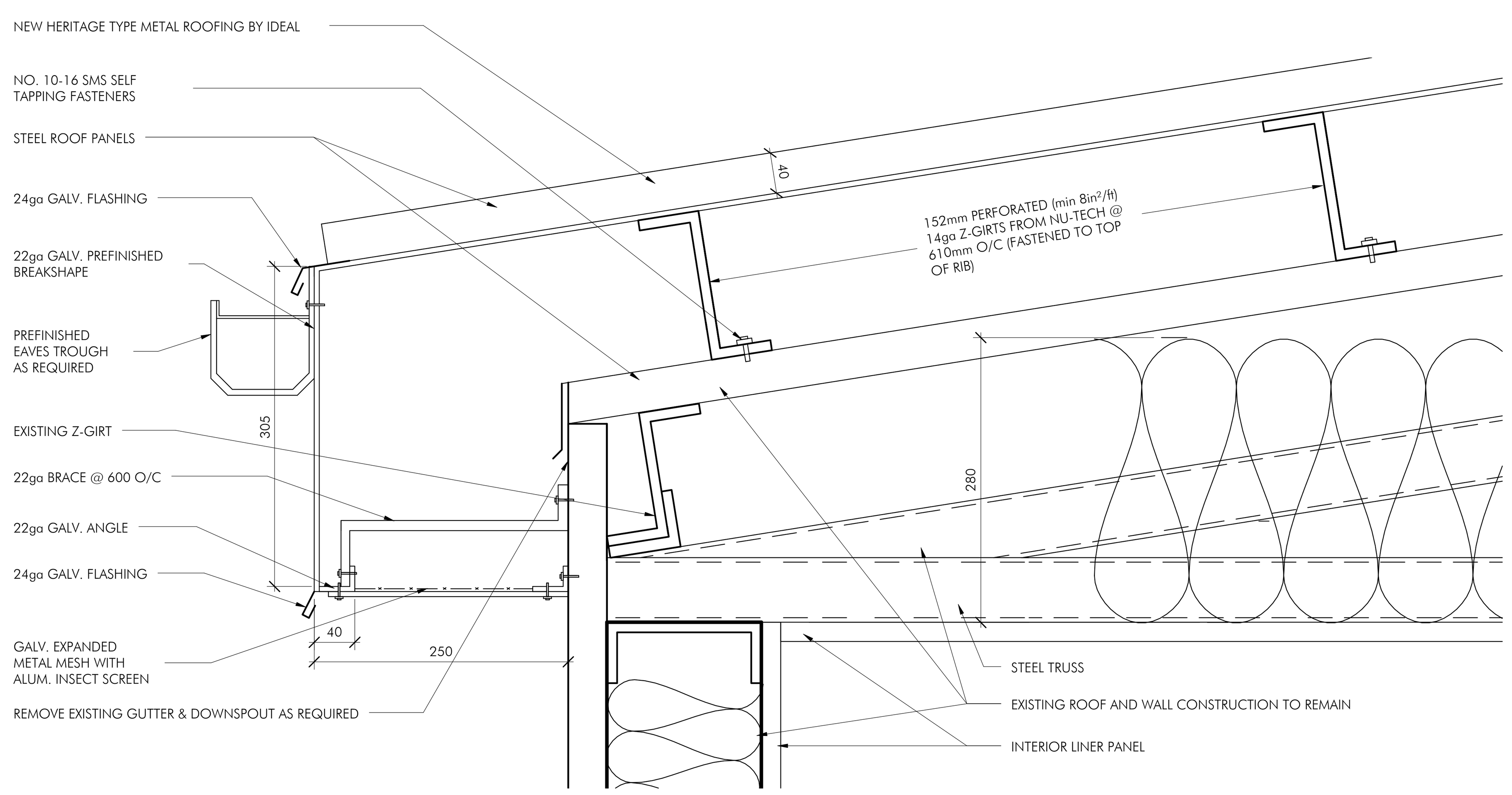


## 3 CALLOUT @ EAVES

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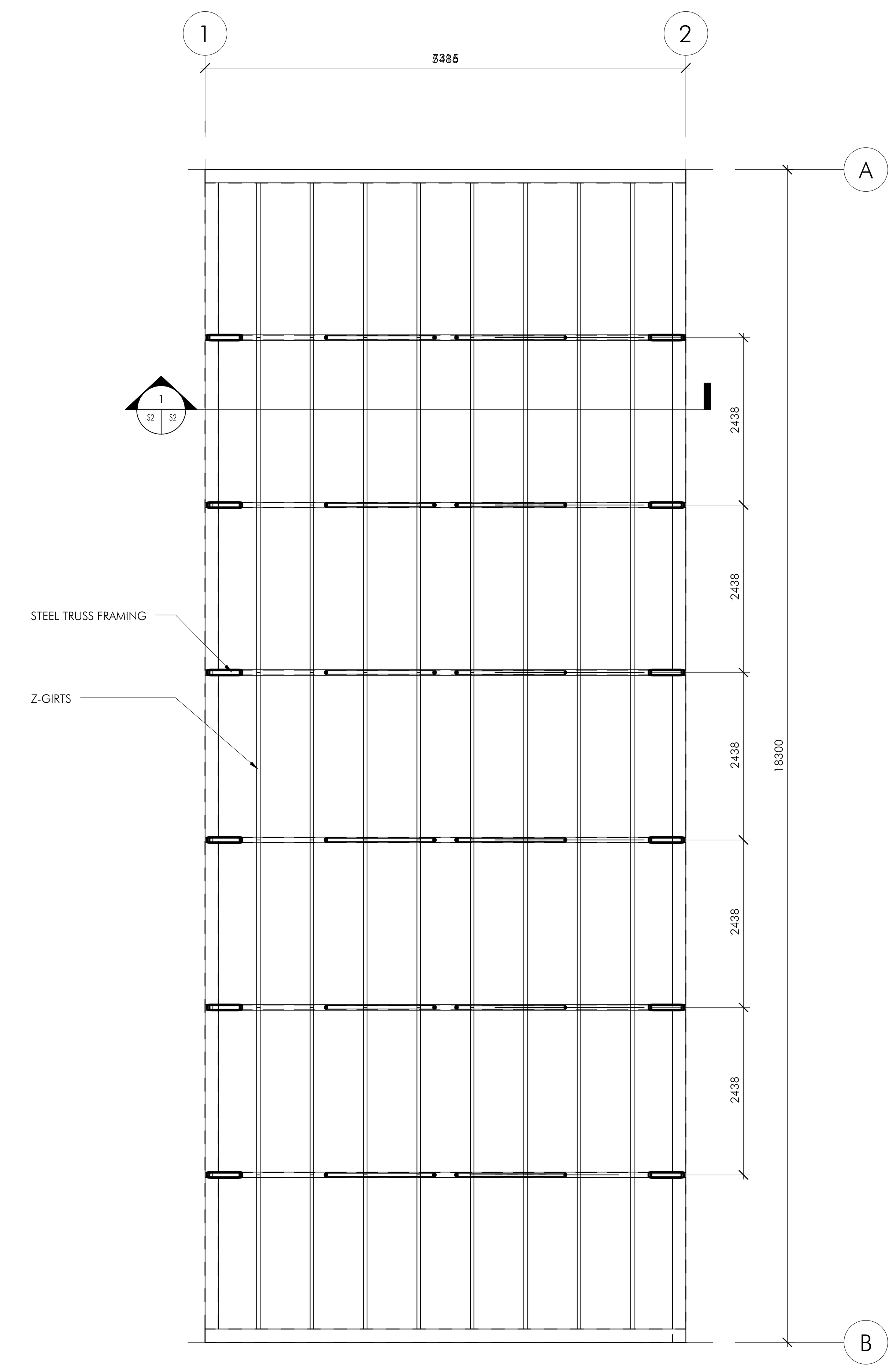


## 4 ROOF PLAN

S2 scale = 1 : 50

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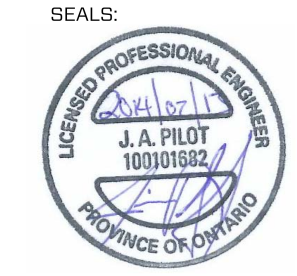
| "0" | 14/02/13 | ISSUED FOR CONSTRUCTION |
| REVISION | DATE | DESCRIPTION |

SEALS:




THIS DRAWING IS NOT TO BE USED FOR CONSTRUCTION WITHOUT A PROFESSIONAL SIGNATURE THROUGH THE SEAL.



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PROJECT NAME:

Hydro One

Remotes Roof Upgrades

SHEET TITLE:

BIG TROUT LAKE PLAN & DETAILS

DATE: 14/02/13

DRAWN: KPD

PROJECT: 2013155

# S2

METSCO
MAKING IT POSSIBLE

19 July 2017

Una O'Reilly
Business Integration Manager
Hydro One Remote Communities Inc.
12th Floor, North Tower
483 Bay Street,
Toronto, ON; M5G 2P5

Dear Una,

## Re: Consolidated Distribution System Plan

This letter is to confirm that METSCO Energy Solutions Inc. has assisted Hydro One Remote Communities Inc. (Remotes) with the creation of a Consolidated Distribution System Plan (DSP) as part of Remotes' 2018 Cost of Service Application. The DSP has been prepared in accordance with the Ontario Energy Board's (OEB's) *Chapter 5 Consolidated Distribution System Plan Filing Requirements dated 28 March 2013.* Remotes' DSP supports the four key objectives from the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (*RRFE*): customer focus, operational effectiveness, public policy responsiveness, and financial performance.

Best regards,

Alex Bakulev
Vice President, Strategy and Assets

METSCO Energy Solutions
metsco.ca

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# RATE BASE AND WORKING CAPITAL

## 1.0 INTRODUCTION

This exhibit provides the forecast of Remotes' rate base for the 2018 test year and provides a detailed description of each of the rate base components.

In accordance with the 2006 Electricity Distribution Rate Handbook ("Handbook") and the "Filing Requirements" updated by the Board on July 14, 2017, the rate base underlying the test year revenue requirement includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are gross plant in service minus accumulated depreciation and contributed capital[1]. Working capital is calculated using the formula as described in Section 5.4 of 2006 Electricity Distribution Rate Handbook.

## 2.0 UTILITY RATE BASE

Utility rate base for Remotes for the test year is filed at Exhibit C2, Tab 1, Schedule 1. Remotes' forecast rate base for the test year is $44,445K.

[1] Contributed capital refers to amounts contributed by third parties to specific capital projects, e.g. Joint Use Assets, Customer Contributions

**Table 1**

**Remotes Rate Base (in $K)**

| **Description** | **Board Approved 2013** | **Test Year 2018** |
|---|---|---|
| Gross Plant | 60,084 | 71,866 |
| Accumulated Depreciation | (24,740) | (31,182) |
| Net Plant | **35,344** | **40,684** |
| Cash Working Capital | 5,746 | 3,761 |
| **Distribution Rate Base** | **41,090** | **44,445** |
| *$ Change* | | *3,335* |
| *% Change* | | *8.2%* |

The mid-year gross plant balance reflects the capital expenditure programs forecast for the bridge and test years. These programs are described in detail in the company's written evidence and supporting schedules filed in the DSP at Exhibit B1, Tab 1, Schedule 1, Section 2.1.1. The justification for capital projects in excess of $283K (0.5% of revenue requirement) are filed at Exhibit B1, Tab 1, Schedule 1, Appendix A.

Continuity schedules are provided in Exhibit C2, Tab 2, Schedule 1, Attachments 1 through 6.

**Table 2**

**Continuity of Fixed Assets Summary (in $K)**

| Description | Board Approved | Historic | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| Opening Gross Asset Balance | 58,973 | 54,790 | 58,905 | 63,601 | 65,373 | 67,532 | 70,664 |
| In-Service Additions | 7,486 | 9,203 | 5,970 | 3,278 | 4,656 | 3,606 | 3,197 |
| Retirements | (5,264) | (5,088) | (1,274) | (1,506) | (1,915) | (474) | (793) |
| Adjustments | - | - | - | - | (582) | - | - |
| Closing Gross Asset Balance | 61,195 | 58,905 | 63,601 | 65,373 | 67,532 | 70,664 | 73,068 |
| Mid-Year Gross Asset Balance | 60,084 | 56,848 | 61,253 | 64,487 | 66,453 | 69,098 | 71,866 |
| *$ Change (2018 Test vs. 2013 Board Approved)* | | | | | | | *11,782* |
| *% Change (2018 Test vs. 2013 Board Approved)* | | | | | | | *19.6%* |

In-service additions reflect the placing in-service of Remotes' capital programs. These programs are described in detail at Exhibit B1, Tab 1, Schedule 1, Section 2.1.1.

Retirements in 2013 are higher than typical when compared to all other years mainly due to an increased volume of retirements related to engine replacements. 2013 also includes the retirement of major assets replaced during the Weagamow upgrade. The slight increase in 2016 (over 2014 and 2015) reflects the retirement of assets replaced during Fort Severn, Deer Lake, and Kasabonika Station upgrades. Retirements in 2017 and 2018 are expected to decrease as fewer Station upgrades are expected to be placed into service and only one engine replacement is planned.

The nature and composition of Remotes' assets are described in detail in Exhibit B1, Tab 1, Schedule 1, Section 2.1.1

## 3.0 WORKING CAPITAL

Working capital is at 7.5% of eligible OM&A expenses per the Filing Requirements for Electricity Transmission and Distribution Applications, updated July 14, 2017. A detailed calculation is found in Exhibit C2, Tab 5, Schedule 1.

**Table 3**

| **Working Capital Calculation** | **(in $K)** |
|---|---|
| Total Eligible OM&A Expenses | 50,143 |
| Working Capital Allowance @ 7.5% | 3,761 |

# INTEREST CAPITALIZED AND CAPITALIZATION OF OVERHEADS

## 1.0 INTEREST CAPITALIZED

Consistent with the Board's Decision in EB-2008-0408, effective January 1, 2012, no allowance for funds used during construction ("AFUDC") rate is specified by the Board for use by Hydro One. Hydro One was directed to base its interest capitalization rate on its embedded cost of debt used to finance capital expenditures. This is consistent with Hydro One's adoption of United States generally accepted accounting principles ("US GAAP") per the Board's Decision in EB-2011-0399 and US GAAP requirements for determination of interest capitalized. The rates used in calculating capitalized interest for the bridge and test years represent the effective rate of Remotes' forecast average debt portfolio during the year.

The interest capitalization rate/AFUDC rate for historical, bridge and test years are shown in Table 1:

**Table 1**

**Interest Capitalization Rates**

| Year | | Interest Capitalized / AFUDC | |
|---|---|---|---|
| | | **Rate (%)** | **(in $K)** |
| | **Board Approved 2013** | 4.3 | 266 |
| **Historical** | **2013** | 5.6 | 376 |
| | **2014** | 4.8 | 146 |
| | **2015** | 4.6 | 97 |
| | **2016** | 5.2 | 115 |
| **Forecast** | **2017** | 5.8 | 176 |
| | **2018** | 4.4 | 117 |

## 2.0 CAPITALIZATION OF OVERHEADS

Remotes capitalizes costs that are directly attributable to the acquisition and construction of capital projects. Remotes also capitalizes certain overhead and indirect costs that are supporting capital projects. With the Board's approval of US GAAP as the basis for regulatory accounting and rate setting for Remotes and consistent with the Board's Decision in EB-2012-0137, Remotes continues to capitalize attributable overhead costs consistent with US GAAP.

The Remotes' overhead capitalization rate is a calculated percentage representing the amount of Common Corporate Functions and Services ("CCFS") overhead costs that are required to support capital projects in a given year. Specifically, this rate reflects the total CCFS amounts to be capitalized as a percentage of total capital expenditures. Due to the lumpiness of Remotes' capital program, CCFS amounts to be capitalized are determined based a 3-year average of direct capital expenditures as a percentage of the total capital and OM&A work program. The overhead capitalization rate for 2018 is 4.9%. Hydro One Networks in 2007 began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs.

The following table shows capitalized overheads, and the related overhead capitalization rates for the historical, bridge and test years.

**Table 2**

**Overhead Capitalization - Historical, Bridge and Test Years**

| | **Board Approved 2013** | **Historic** | | | | **Bridge** | **Test** |
|---|---|---|---|---|---|---|---|
| | | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Total capitalized overheads (in $K) | 455 | 320 | 342 | 556 | 410 | 562 | 448 |
| Capitalized overhead rate (%) | 5.5 | 5.5 | 6.0 | 5.9 | 5.6 | 4.9 | 4.9 |

**HYDRO ONE REMOTE COMMUNITIES INC**
**Statement of Utility Rate Base**
Test Year (2018)
Year Ending December 31
(in $K)

| Line No. | Particulars | | 2018 |
|---|---|---|---|
| | Electric Utility Plant | | |
| 1 | Gross plant at cost | $ | 71,866 |
| 2 | Less: accumulated depreciation | | (31,182) |
| 3 | Net plant in service | $ | 40,684 |
| 4 | Cash working capital | $ | 3,761 |
| **5** | **Total rate base** | **$** | **44,445** |

# HYDRO ONE REMOTES FIXED ASSET CONTINUITY SCHEDULES 2013 TO 2018

Attachment 1: 2013 Fixed Asset Continuity Schedule

Attachment 2: 2014 Fixed Asset Continuity Schedule

Attachment 3: 2015 Fixed Asset Continuity Schedule

Attachment 4: 2016 Fixed Asset Continuity Schedule

Attachment 5: 2017 Fixed Asset Continuity Schedule

Attachment 6: 2018 Fixed Asset Continuity Schedule

# Appendix 2-BA
## Fixed Asset Continuity Schedule 2013

| | |
|---|---|
| Accounting Standard | USGAAP |
| Year | 2013 |

| CCA Class | OEB | Description | Cost: Opening Balance | Cost: Additions | Cost: Disposals | Cost: Closing Balance | Accumulated Depreciation: Opening Balance | Accumulated Depreciation: Additions | Accumulated Depreciation: Disposals | Accumulated Depreciation: Dep'n Study Adj | Accumulated Depreciation: Closing Balance | Net Book Value |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 | 1611 | Computer Software (Formally known as Account 1925) | | | | | | | | | | |
| CEC | 1612 | Land Rights (Formally known as Account 1906) | | | | | | | | | | |
| N/A | 1615 | Land | $ 407,800 | $ - | $ - | $ 407,800 | -$ 407,800 | $ - | $ - | $ - | -$ 407,800 | $ - |
| 1 | 1620 | Buildings &Fixtures | $ 4,971,094 | $ 110,891 | -$ 116,529 | $ 4,965,456 | -$ 1,387,455 | -$ 124,399 | $ 116,529 | -$ 422,526 | -$ 1,817,851 | $ 3,147,605 |
| 17 | 1650 | Reservoirs Dams & Water | $ 670,778 | $ - | $ - | $ 670,778 | -$ 750,200 | $ - | $ - | $ 79,422 | -$ 670,778 | $ - |
| 17 | 1665 | Fuel Holders Produce | $ 5,369,567 | $ 1,982,200 | -$ 550,785 | $ 6,800,982 | -$ 1,182,306 | -$ 169,359 | $ 550,785 | -$ 106,253 | -$ 907,133 | $ 5,893,849 |
| 17 | 1670 | Prime Movers | $ 14,407,210 | $ 3,190,922 | -$ 3,342,607 | $ 14,255,525 | -$ 14,087,491 | -$ 1,120,389 | $ 3,341,207 | $ 2,371,121 | -$ 9,495,552 | $ 4,759,973 |
| 17 | 1675 | Generators | $ 7,251,100 | $ 1,374,135 | -$ 844,293 | $ 7,780,942 | -$ 2,025,232 | -$ 388,504 | $ 844,293 | -$ 1,905,096 | -$ 3,474,539 | $ 4,306,403 |
| 17 | 1680 | Accessory Electc Equ | $ 1,476,018 | $ 1,017,063 | -$ 41,406 | $ 2,451,675 | -$ 329,267 | -$ 145,497 | $ 41,406 | -$ 369,586 | -$ 802,944 | $ 1,648,731 |
| 17 | 1685 | Misc Power Plant Equ | $ 3,900,267 | $ 35,011 | $ - | $ 3,935,278 | -$ 1,886,095 | -$ 98,641 | $ - | $ 43,345 | -$ 1,941,391 | $ 1,993,887 |
| N/A | 1805 | Land | $ 294,456 | $ - | $ - | $ 294,456 | -$ 55,912 | -$ 5,712 | $ - | -$ 33,995 | -$ 95,619 | $ 198,837 |
| CEC | 1806 | L&Rights | $ 234,126 | $ - | $ - | $ 234,126 | -$ 68,970 | -$ 2,271 | $ - | $ 8,335 | -$ 62,906 | $ 171,220 |
| 47 | 1808 | Buildings | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | 1810 | Leasehold Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1815 | Transformer Station Equipment >50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1820 | Distribution Station Equipment <50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1825 | Storage Battery Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1830 | Poles, Towers & Fixtures | $ 2,132,794 | $ 279,003 | -$ 44,640 | $ 2,367,157 | -$ 430,375 | -$ 41,705 | $ 44,640 | $ 16,833 | -$ 410,607 | $ 1,956,550 |
| 47 | 1835 | Overhead Conductors & Devices | $ 1,553,299 | $ 118,872 | -$ 88,616 | $ 1,583,555 | -$ 416,715 | -$ 31,672 | $ 88,616 | $ 11,711 | -$ 348,060 | $ 1,235,495 |
| 47 | 1840 | Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1845 | Underground Conductors & Devices | $ 186,177 | $ - | $ - | $ 186,177 | -$ 121,280 | -$ 5,641 | $ - | $ 5,015 | -$ 121,906 | $ 64,271 |
| 47 | 1850 | Line Transformers | $ 1,833,988 | $ 94,879 | -$ 9,990 | $ 1,918,877 | -$ 514,795 | -$ 45,834 | $ 8,124 | $ 4,490 | -$ 548,015 | $ 1,370,862 |
| 47 | 1855 | Services (Overhead & Underground) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1860 | Meters | $ 308,083 | $ 214,160 | $ - | $ 522,243 | -$ 176,717 | -$ 45,472 | $ - | $ 61,360 | -$ 160,829 | $ 361,414 |
| 47 | 1860 | Meters (Smart Meters) | | | | $ - | | | | | $ - | $ - |
| N/A | 1905 | Land | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 1 & 3 | 1908 | Buildings & Fixtures | $ 8,911,212 | $ 571,911 | -$ 1,766 | $ 9,481,357 | -$ 1,425,193 | -$ 180,309 | $ 1,766 | $ 126,571 | -$ 1,477,165 | $ 8,004,192 |
| 13 | 1910 | Leasehold Improvements | $ 68,062 | $ - | $ - | $ 68,062 | -$ 10,343 | -$ 7,677 | $ - | $ - | -$ 18,020 | $ 50,042 |
| 8 | 1915-A | Office Furniture & Equipment (10 years) | | | | $ - | | $ - | | | $ - | $ - |
| 8 | 1915 | Office Furniture & Equipment (5 & 7 years) | $ 68,884 | $ - | -$ 4,259 | $ 64,625 | -$ 23,348 | -$ 9,389 | $ 4,259 | $ - | -$ 28,478 | $ 36,147 |
| 10 | 1920-A | Computer Equipment - Hardware | | | | $ - | | | | | $ - | $ - |
| 45 | 1920-B | Computer Equip.-Hardware(Post Mar. 22/04) | | | | $ - | | | | | $ - | $ - |
| 50 | 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 75,143 | $ - | -$ 13,960 | $ 61,183 | -$ 35,875 | -$ 13,625 | $ 13,960 | $ 1,024 | -$ 34,516 | $ 26,667 |
| 10 | 1930 | Transportation Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1935 | Stores Equipment | $ 269,672 | $ - | -$ 7,403 | $ 262,269 | -$ 118,780 | -$ 33,246 | $ 7,403 | -$ 1 | -$ 144,624 | $ 117,645 |
| 8 | 1940 | Tools, Shop & Garage Equipment | $ 39,541 | $ 21,224 | $ - | $ 60,765 | -$ 10,480 | -$ 8,359 | $ - | -$ 84 | -$ 18,923 | $ 41,842 |
| 8 | 1945 | Measurement & Testing Equipment | $ 53,730 | $ 57,030 | $ - | $ 110,760 | -$ 14,688 | -$ 16,449 | $ - | -$ 1 | -$ 31,138 | $ 79,622 |
| 8 | 1950 | Power Operated Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1955 | Communications Equipment | $ 20,332 | $ - | $ - | $ 20,332 | -$ 30,738 | -$ 687 | $ - | $ 4,679 | -$ 26,746 | -$ 6,414 |
| 8 | 1955 | Communication Equipment (Smart Meters) | | | | $ - | | | | | $ - | $ - |
| 8 | 1960 | Miscellaneous Equipment | $ 286,351 | $ 136,214 | -$ 22,335 | $ 400,230 | -$ 97,460 | -$ 68,658 | $ 22,335 | $ 263 | -$ 143,520 | $ 256,710 |
| 47 | 1975 | Load Management Controls Utility Premises | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1980 | System Supervisor Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1985 | Miscellaneous Fixed Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1995 | Contributions & Grants | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| N/A | A | Maj Rollup Acc Dep Suspense | | | | | -$ 343,689 | $ - | | $ 103,373 | -$ 240,316 | -$ 240,316 |
| N/A | B | Acc Dep - Contra for Group Retirement | | | | | $ 172,061 | $ - | $ - | $ - | $ 172,061 | $ 172,061 |
| N/A | C | Suspense/Conversion/Error | | | | | $ - | $ - | $ - | $ - | $ - | $ - |
| | etc. | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | Total | $ 54,789,684 | $ 9,203,515 | -$ 5,088,589 | $ 58,904,610 | -$ 25,779,143 | -$ 2,563,495 | $ 5,085,323 | $ - | -$ 23,257,315 | $ 35,647,295 |

| | | |
|---|---|---|
| 10 | | Transportation |
| 8 | | Stores Equipment |

| | |
|---|---|
| **Less:** *Fully Allocated Depreciation* | |
| Transportation | |
| Stores Equipment | |
| **Net Depreciation** | -$ 2,563,495 |

***Notes:***

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

## Appendix 2-BA
## Fixed Asset Continuity Schedule 2014

**Accounting Standard** USGAAP
**Year** 2014

| CCA Class | OEB | Description | Cost: Opening Balance | Cost: Additions | Cost: Disposals | Cost: Closing Balance | Accumulated Depreciation: Opening Balance | Accumulated Depreciation: Additions | Accumulated Depreciation: Disposals | Accumulated Depreciation: Closing Balance | Net Book Value |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 | 1611 | Computer Software (Formally known as Account 1925) | | | | | | | | | |
| CEC | 1612 | Land Rights (Formally known as Account 1906) | | | | | | | | | |
| N/A | 1615 | Land | $ 407,800 | $ - | $ - | $ 407,800 | -$ 407,800 | $ - | $ - | -$ 407,800 | $ - |
| 1 | 1620 | Buildings &Fixtures | $ 4,965,456 | $ - | $ - | $ 4,965,456 | -$ 1,817,851 | -$ 123,387 | $ - | -$ 1,941,238 | $ 3,024,218 |
| 17 | 1650 | Reservoirs Dams & Water | $ 670,778 | $ - | $ - | $ 670,778 | -$ 670,778 | $ - | $ - | -$ 670,778 | $ - |
| 17 | 1665 | Fuel Holders Produce | $ 6,800,982 | $ 1,234,762 | -$ 375,944 | $ 7,659,800 | -$ 907,133 | -$ 206,904 | $ 375,944 | -$ 738,093 | $ 6,921,707 |
| 17 | 1670 | Prime Movers | $ 14,255,525 | $ 1,853,579 | -$ 468,634 | $ 15,640,470 | -$ 9,495,555 | -$ 1,044,464 | $ 469,834 | -$ 10,070,185 | $ 5,570,285 |
| 17 | 1675 | Generators | $ 7,780,942 | $ 618,691 | -$ 311,637 | $ 8,087,996 | -$ 3,474,539 | -$ 411,702 | $ 311,637 | -$ 3,574,604 | $ 4,513,392 |
| 17 | 1680 | Accessory Electc Equ | $ 2,451,675 | $ 323,546 | $ - | $ 2,775,221 | -$ 802,944 | -$ 142,172 | $ - | -$ 945,116 | $ 1,830,105 |
| 17 | 1685 | Misc Power Plant Equ | $ 3,935,278 | $ 273,666 | -$ 10,002 | $ 4,198,942 | -$ 1,941,391 | -$ 106,123 | $ 10,002 | -$ 2,037,512 | $ 2,161,430 |
| N/A | 1805 | Land | $ 294,456 | $ - | $ - | $ 294,456 | -$ 95,619 | -$ 5,712 | $ - | -$ 101,331 | $ 193,125 |
| CEC | 1806 | L&Rights | $ 234,126 | $ - | $ - | $ 234,126 | -$ 62,906 | -$ 2,271 | $ - | -$ 65,177 | $ 168,949 |
| 47 | 1808 | Buildings | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | 1810 | Leasehold Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1815 | Transformer Station Equipment >50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1820 | Distribution Station Equipment <50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1825 | Storage Battery Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1830 | Poles, Towers & Fixtures | $ 2,367,157 | $ 455,279 | -$ 3,607 | $ 2,818,829 | -$ 410,607 | -$ 48,533 | $ 3,607 | -$ 455,533 | $ 2,363,296 |
| 47 | 1835 | Overhead Conductors & Devices | $ 1,583,555 | $ 259,132 | -$ 1,721 | $ 1,840,966 | -$ 348,060 | -$ 34,026 | $ 1,721 | -$ 380,365 | $ 1,460,601 |
| 47 | 1840 | Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1845 | Underground Conductors & Devices | $ 186,177 | $ 106,185 | $ - | $ 292,362 | -$ 121,906 | -$ 7,444 | $ - | -$ 129,350 | $ 163,012 |
| 47 | 1850 | Line Transformers | $ 1,918,877 | $ 201,371 | -$ 31,885 | $ 2,088,363 | -$ 548,015 | -$ 49,593 | $ 20,545 | -$ 577,063 | $ 1,511,300 |
| 47 | 1855 | Services (Overhead & Underground) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1860 | Meters | $ 522,243 | $ 40,166 | $ - | $ 562,409 | -$ 160,829 | -$ 35,721 | $ - | -$ 196,550 | $ 365,859 |
| 47 | 1860 | Meters (Smart Meters) | $ - | | | $ - | $ - | | | $ - | $ - |
| N/A | 1905 | Land | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 1 & 3 | 1908 | Buildings & Fixtures | $ 9,481,357 | $ 368,887 | $ - | $ 9,850,244 | -$ 1,477,165 | -$ 189,482 | $ - | -$ 1,666,647 | $ 8,183,597 |
| 13 | 1910 | Leasehold Improvements | $ 68,062 | $ 47,121 | $ - | $ 115,183 | -$ 18,020 | -$ 7,677 | $ - | -$ 25,697 | $ 89,486 |
| 8 | 1915-A | Office Furniture & Equipment (10 years) | $ - | | | $ - | $ - | | | $ - | $ - |
| 8 | 1915 | Office Furniture & Equipment (5 & 7 years) | $ 64,625 | $ 21,700 | $ - | $ 86,325 | -$ 28,478 | -$ 10,004 | $ - | -$ 38,482 | $ 47,843 |
| 10 | 1920-A | Computer Equipment - Hardware | $ - | | | $ - | $ - | | | $ - | $ - |
| 45 | 1920-B | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | | | $ - | $ - | | | $ - | $ - |
| 50 | 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 61,183 | $ - | -$ 3,861 | $ 57,322 | -$ 34,516 | -$ 11,849 | $ 3,861 | -$ 42,504 | $ 14,818 |
| 10 | 1930 | Transportation Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1935 | Stores Equipment | $ 262,269 | $ - | -$ 60,989 | $ 201,280 | -$ 144,624 | -$ 28,971 | $ 60,989 | -$ 112,606 | $ 88,674 |
| 8 | 1940 | Tools, Shop & Garage Equipment | $ 60,765 | $ 26,784 | $ - | $ 87,549 | -$ 18,923 | -$ 12,360 | $ - | -$ 31,283 | $ 56,266 |
| 8 | 1945 | Measurement & Testing Equipment | $ 110,760 | $ 19,962 | -$ 5,287 | $ 125,435 | -$ 31,138 | -$ 23,619 | $ 5,287 | -$ 49,470 | $ 75,965 |
| 8 | 1950 | Power Operated Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1955 | Communications Equipment | $ 20,332 | $ - | $ - | $ 20,332 | -$ 26,746 | -$ 687 | $ - | -$ 27,433 | -$ 7,101 |
| 8 | 1955 | Communication Equipment (Smart Meters) | $ - | | | $ - | $ - | | | $ - | $ - |
| 8 | 1960 | Miscellaneous Equipment | $ 400,230 | $ 118,868 | $ - | $ 519,098 | -$ 143,520 | -$ 91,350 | $ - | -$ 234,870 | $ 284,228 |
| 47 | 1975 | Load Management Controls Utility Premises | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1980 | System Supervisor Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1985 | Miscellaneous Fixed Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1995 | Contributions & Grants | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| N/A | A | Maj Rollup Acc Dep Suspense | $ - | | | | -$ 240,316 | $ - | $ - | -$ 240,316 | -$ 240,316 |
| N/A | B | Acc Dep - Contra for Group Retirement | $ - | | | | $ 172,061 | $ - | $ - | $ 172,061 | $ 172,061 |
| N/A | C | Suspense/Conversion/Error | $ - | | | | $ - | $ - | $ - | $ - | $ - |
| - | etc. | | | | | | | | | | |
| - | | | | | | | | | | | |
| - | | Total | $ 58,904,610 | $ 5,969,699 | -$ 1,273,567 | $ 63,600,742 | -$ 23,257,318 | -$ 2,594,051 | $ 1,263,427 | -$ 24,587,942 | $ 39,012,800 |

| | | |
|---|---|---|
| 10 | | Transportation |
| 8 | | Stores Equipment |

| **Less:** *Fully Allocated Depreciation* | |
|---|---|
| Transportation | |
| Stores Equipment | |
| **Net Depreciation** | -$ 2,594,051 |

***Notes:***

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

# Appendix 2-BA
## Fixed Asset Continuity Schedule 2015

**Accounting Standard** USGAAP
**Year** 2015

| CCA Class | OEB | Description | Cost: Opening Balance | Cost: Additions | Cost: Disposals | Cost: Closing Balance | Accumulated Depreciation: Opening Balance | Accumulated Depreciation: Additions | Accumulated Depreciation: Disposals | Accumulated Depreciation: Closing Balance | Net Book Value |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 | 1611 | Computer Software (Formally known as Account 1925) | | | | | | | | | |
| CEC | 1612 | Land Rights (Formally known as Account 1906) | | | | | | | | | |
| N/A | 1615 | Land | $ 407,800 | $ - | $ - | $ 407,800 | -$ 407,800 | $ - | $ - | -$ 407,800 | $ - |
| 1 | 1620 | Buildings &Fixtures | $ 4,965,456 | $ 385,060 | $ - | $ 5,350,516 | -$ 1,941,238 | -$ 132,687 | $ - | -$ 2,073,925 | $ 3,276,591 |
| 17 | 1650 | Reservoirs Dams & Water | $ 670,778 | $ - | $ - | $ 670,778 | -$ 670,778 | $ - | $ - | -$ 670,778 | $ - |
| 17 | 1665 | Fuel Holders Produce | $ 7,659,800 | $ - | -$ 11,643 | $ 7,648,157 | -$ 738,093 | -$ 212,150 | $ 11,643 | -$ 938,600 | $ 6,709,557 |
| 17 | 1670 | Prime Movers | $ 15,640,470 | $ 973,391 | -$ 704,713 | $ 15,909,148 | -$ 10,070,185 | -$ 1,070,467 | $ 704,913 | -$ 10,435,739 | $ 5,473,409 |
| 17 | 1675 | Generators | $ 8,087,996 | $ 822,035 | -$ 614,528 | $ 8,295,503 | -$ 3,574,604 | -$ 421,061 | $ 614,528 | -$ 3,381,137 | $ 4,914,366 |
| 17 | 1680 | Accessory Electc Equ | $ 2,775,221 | $ 95 | $ - | $ 2,775,316 | -$ 945,116 | -$ 150,977 | $ - | -$ 1,096,093 | $ 1,679,223 |
| 17 | 1685 | Misc Power Plant Equ | $ 4,198,942 | $ 4,560 | $ - | $ 4,203,502 | -$ 2,037,512 | -$ 109,075 | $ - | -$ 2,146,587 | $ 2,056,915 |
| N/A | 1805 | Land | $ 294,456 | $ - | $ - | $ 294,456 | -$ 101,331 | -$ 5,712 | $ - | -$ 107,043 | $ 187,413 |
| CEC | 1806 | L&Rights | $ 234,126 | $ - | $ - | $ 234,126 | -$ 65,177 | -$ 2,271 | $ - | -$ 67,448 | $ 166,678 |
| 47 | 1808 | Buildings | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | 1810 | Leasehold Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1815 | Transformer Station Equipment >50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1820 | Distribution Station Equipment <50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1825 | Storage Battery Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1830 | Poles, Towers & Fixtures | $ 2,818,829 | $ 79,105 | -$ 62,309 | $ 2,835,625 | -$ 455,533 | -$ 50,610 | $ 35,759 | -$ 470,384 | $ 2,365,241 |
| 47 | 1835 | Overhead Conductors & Devices | $ 1,840,966 | $ 139,846 | $ 50,208 | $ 2,031,020 | -$ 380,365 | -$ 37,146 | $ 2,891 | -$ 414,620 | $ 1,616,400 |
| 47 | 1840 | Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1845 | Underground Conductors & Devices | $ 292,362 | $ - | $ - | $ 292,362 | -$ 129,350 | -$ 7,701 | $ - | -$ 137,051 | $ 155,311 |
| 47 | 1850 | Line Transformers | $ 2,088,363 | $ 120,118 | -$ 38,042 | $ 2,170,439 | -$ 577,063 | -$ 51,922 | $ 11,403 | -$ 617,582 | $ 1,552,857 |
| 47 | 1855 | Services (Overhead & Underground) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1860 | Meters | $ 562,409 | $ 33,655 | $ - | $ 596,064 | -$ 196,550 | -$ 38,233 | $ - | -$ 234,783 | $ 361,281 |
| 47 | 1860 | Meters (Smart Meters) | $ - | | | $ - | $ - | | | $ - | $ - |
| N/A | 1905 | Land | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 1 & 3 | 1908 | Buildings & Fixtures | $ 9,850,244 | $ 437,828 | $ - | $ 10,288,072 | -$ 1,666,647 | -$ 200,421 | $ - | -$ 1,867,068 | $ 8,421,004 |
| 13 | 1910 | Leasehold Improvements | $ 115,183 | $ - | $ - | $ 115,183 | -$ 25,697 | -$ 15,650 | $ - | -$ 41,347 | $ 73,836 |
| 8 | 1915-A | Office Furniture & Equipment (10 years) | $ - | | | $ - | $ - | | | $ - | $ - |
| 8 | 1915 | Office Furniture & Equipment (5 & 7 years) | $ 86,325 | $ - | -$ 10,900 | $ 75,425 | -$ 38,482 | -$ 10,775 | $ 10,900 | -$ 38,357 | $ 37,068 |
| 10 | 1920-A | Computer Equipment - Hardware | $ - | | | $ - | $ - | | | $ - | $ - |
| 45 | 1920-B | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | | | $ - | $ - | | | $ - | $ - |
| 50 | 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 57,322 | $ - | -$ 5,504 | $ 51,818 | -$ 42,504 | -$ 9,497 | $ 5,504 | -$ 46,497 | $ 5,321 |
| 10 | 1930 | Transportation Equipment | $ - | $ 3,488 | -$ 3,488 | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1935 | Stores Equipment | $ 201,280 | $ - | -$ 45,357 | $ 155,923 | -$ 112,606 | -$ 22,325 | $ 45,357 | -$ 89,574 | $ 66,349 |
| 8 | 1940 | Tools, Shop & Garage Equipment | $ 87,549 | $ 4,329 | -$ 3,039 | $ 88,839 | -$ 31,283 | -$ 14,446 | $ 3,039 | -$ 42,690 | $ 46,149 |
| 8 | 1945 | Measurement & Testing Equipment | $ 125,435 | $ 9,735 | -$ 8,717 | $ 126,453 | -$ 49,470 | -$ 25,189 | $ 8,717 | -$ 65,942 | $ 60,511 |
| 8 | 1950 | Power Operated Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1955 | Communications Equipment | $ 20,332 | $ - | $ - | $ 20,332 | -$ 27,433 | -$ 687 | $ - | -$ 28,120 | -$ 7,788 |
| 8 | 1955 | Communication Equipment (Smart Meters) | $ - | | | $ - | $ - | | | $ - | $ - |
| 8 | 1960 | Miscellaneous Equipment | $ 519,098 | $ 264,539 | -$ 47,778 | $ 735,859 | -$ 234,870 | -$ 122,464 | $ 51,266 | -$ 306,068 | $ 429,791 |
| 47 | 1975 | Load Management Controls Utility Premises | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1980 | System Supervisor Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1985 | Miscellaneous Fixed Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1995 | Contributions & Grants | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| N/A | A | Maj Rollup Acc Dep Suspense | $ - | $ - | $ - | $ - | -$ 240,316 | $ - | $ - | -$ 240,316 | -$ 240,316 |
| N/A | B | Acc Dep - Contra for Group Retirement | $ - | $ - | $ - | $ - | $ 172,061 | $ - | $ - | $ 172,061 | $ 172,061 |
| N/A | C | Suspense/Conversion/Error | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| - | etc. | | | | | | | | | | |
| - | | | | | | | | | | | |
| - | | **Total** | **$ 63,600,742** | **$ 3,277,784** | **-$ 1,505,810** | **$ 65,372,716** | **-$ 24,587,942** | **-$ 2,711,466** | **$ 1,505,920** | **-$ 25,793,488** | **$ 39,579,228** |

| | | |
|---|---|---|
| 10 | | Transportation |
| 8 | | Stores Equipment |

**Less:** *Fully Allocated Depreciation*

| | |
|---|---|
| Transportation | |
| Stores Equipment | |
| **Net Depreciation** | -$ 2,711,466 |

***Notes:***

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

# Appendix 2-BA
## Fixed Asset Continuity Schedule 2016

**Accounting Standard** USGAAP
**Year** 2016

| | | | Cost | | | | | Accumulated Depreciation | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CCA Class** | **OEB** | **Description** | **Opening Balance** | **Additions** | **Disposals** | **Other** | **Closing Balance** | **Opening Balance** | **Additions** | **Disposals** | **Closing Balance** | **Net Book Value** |
| 12 | 1611 | Computer Software (Formally known as Account 1925) | | | | | | | | | | |
| CEC | 1612 | Land Rights (Formally known as Account 1906) | | | | | | | | | | |
| N/A | 1615 | Land | $ 407,800 | $ - | $ - | $ - | $ 407,800 | -$ 407,800 | $ - | $ - | -$ 407,800 | $ - |
| 1 | 1620 | Buildings &Fixtures | $ 5,350,516 | $ 211,340 | $ - | $ - | $ 5,561,856 | -$ 2,073,925 | -$ 137,030 | $ - | -$ 2,210,955 | $ 3,350,901 |
| 17 | 1650 | Reservoirs Dams & Water | $ 670,778 | $ - | $ - | $ - | $ 670,778 | -$ 670,778 | $ - | $ - | -$ 670,778 | $ - |
| 17 | 1665 | Fuel Holders Produce | $ 7,648,157 | $ - | -$ 295,591 | $ - | $ 7,352,566 | -$ 938,600 | -$ 207,882 | $ 295,591 | -$ 850,891 | $ 6,501,675 |
| 17 | 1670 | Prime Movers | $ 15,909,148 | $ 2,150,627 | -$ 1,157,937 | -$ 436,500 | $ 16,465,338 | -$ 10,435,739 | -$ 1,079,006 | $ 1,157,937 | -$ 10,356,808 | $ 6,108,530 |
| 17 | 1675 | Generators | $ 8,295,503 | $ 716,876 | -$ 310,049 | -$ 145,500 | $ 8,556,830 | -$ 3,381,137 | -$ 420,843 | $ 310,049 | -$ 3,491,931 | $ 5,064,899 |
| 17 | 1680 | Accessory Electc Equ | $ 2,775,316 | $ - | $ - | $ - | $ 2,775,316 | -$ 1,096,093 | -$ 150,977 | $ - | -$ 1,247,070 | $ 1,528,246 |
| 17 | 1685 | Misc Power Plant Equ | $ 4,203,502 | $ - | $ - | $ - | $ 4,203,502 | -$ 2,146,587 | -$ 109,075 | $ - | -$ 2,255,662 | $ 1,947,840 |
| N/A | 1805 | Land | $ 294,456 | $ - | $ - | $ - | $ 294,456 | -$ 107,043 | -$ 5,712 | $ - | -$ 112,755 | $ 181,701 |
| CEC | 1806 | L&Rights | $ 234,126 | $ - | $ - | $ - | $ 234,126 | -$ 67,448 | -$ 2,271 | $ - | -$ 69,719 | $ 164,407 |
| 47 | 1808 | Buildings | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | 1810 | Leasehold Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1815 | Transformer Station Equipment >50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1820 | Distribution Station Equipment <50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1825 | Storage Battery Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1830 | Poles, Towers & Fixtures | $ 2,835,625 | $ 293,078 | -$ 607 | $ - | $ 3,128,096 | -$ 470,384 | -$ 53,920 | $ 607 | -$ 523,697 | $ 2,604,399 |
| 47 | 1835 | Overhead Conductors & Devices | $ 2,031,020 | $ 223,571 | -$ 458 | $ - | $ 2,254,133 | -$ 414,620 | -$ 42,713 | $ 458 | -$ 456,875 | $ 1,797,258 |
| 47 | 1840 | Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1845 | Underground Conductors & Devices | $ 292,362 | $ - | $ - | $ - | $ 292,362 | -$ 137,051 | -$ 7,701 | $ - | -$ 144,752 | $ 147,610 |
| 47 | 1850 | Line Transformers | $ 2,170,439 | $ 75,044 | -$ 2,476 | $ - | $ 2,243,007 | -$ 617,582 | -$ 53,207 | 2,132 | -$ 668,657 | $ 1,574,350 |
| 47 | 1855 | Services (Overhead & Underground) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1860 | Meters | $ 596,064 | $ 74,092 | -$ 18,593 | $ - | $ 651,563 | -$ 234,783 | -$ 41,563 | $ 18,593 | -$ 257,753 | $ 393,810 |
| 47 | 1860 | Meters (Smart Meters) | $ - | | | $ - | $ - | $ - | | | $ - | $ - |
| N/A | 1905 | Land | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 1 & 3 | 1908 | Buildings & Fixtures | $ 10,288,072 | $ 801,442 | $ - | $ - | $ 11,089,514 | -$ 1,867,068 | -$ 209,500 | $ - | -$ 2,076,568 | $ 9,012,946 |
| 13 | 1910 | Leasehold Improvements | $ 115,183 | $ - | $ - | $ - | $ 115,183 | -$ 41,347 | -$ 12,993 | $ - | -$ 54,340 | $ 60,843 |
| 8 | 1915-A | Office Furniture & Equipment (10 years) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1915 | Office Furniture & Equipment (5 & 7 years) | $ 75,425 | $ - | $ - | $ - | $ 75,425 | -$ 38,357 | -$ 10,775 | $ - | -$ 49,132 | $ 26,293 |
| 10 | 1920-A | Computer Equipment - Hardware | $ - | | | $ - | $ - | $ - | | | $ - | $ - |
| 45 | 1920-B | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | | | $ - | $ - | $ - | | | $ - | $ - |
| 50 | 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 51,818 | $ - | -$ 24,104 | $ - | $ 27,714 | -$ 46,497 | -$ 4,083 | $ 24,104 | -$ 26,476 | $ 1,238 |
| 10 | 1930 | Transportation Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1935 | Stores Equipment | $ 155,923 | $ - | -$ 10,346 | $ - | $ 145,577 | -$ 89,574 | -$ 18,844 | $ 10,346 | -$ 98,072 | $ 47,505 |
| 8 | 1940 | Tools, Shop & Garage Equipment | $ 88,839 | $ 36,445 | -$ 3,039 | $ - | $ 122,245 | -$ 42,690 | -$ 17,337 | $ 3,039 | -$ 56,988 | $ 65,257 |
| 8 | 1945 | Measurement & Testing Equipment | $ 126,453 | $ - | -$ 4,566 | $ - | $ 121,887 | -$ 65,942 | -$ 23,962 | $ 4,566 | -$ 85,338 | $ 36,549 |
| 8 | 1950 | Power Operated Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1955 | Communications Equipment | $ 20,332 | $ - | $ - | $ - | $ 20,332 | -$ 28,120 | -$ 687 | $ - | -$ 28,807 | -$ 8,475 |
| 8 | 1955 | Communication Equipment (Smart Meters) | $ - | | | $ - | $ - | $ - | | | $ - | $ - |
| 8 | 1960 | Miscellaneous Equipment | $ 735,859 | $ 73,742 | -$ 86,924 | $ - | $ 722,677 | -$ 306,068 | -$ 141,025 | $ 86,924 | -$ 360,169 | $ 362,508 |
| 47 | 1975 | Load Management Controls Utility Premises | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1980 | System Supervisor Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1985 | Miscellaneous Fixed Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1995 | Contributions & Grants | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| N/A | A | Maj Rollup Acc Dep Suspense | $ - | $ - | $ - | $ - | $ - | -$ 240,316 | $ - | $ - | -$ 240,316 | -$ 240,316 |
| N/A | B | Acc Dep - Contra for Group Retirement | $ - | $ - | $ - | $ - | $ - | $ 172,061 | $ - | $ - | $ 172,061 | $ 172,061 |
| N/A | C | Suspense/Conversion/Error | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| - | etc. | | | | | $ - | | | | | | |
| - | | | | | | | | | | | | |
| - | | **Total** | **$ 65,372,716** | **$ 4,656,257** | **-$ 1,914,690** | **-$ 582,000** | **$ 67,532,283** | **-$ 25,793,488** | **-$ 2,751,106** | **$ 1,914,346** | **-$ 26,630,248** | **$ 40,902,035** |

| | | |
|---|---|---|
| 10 | | Transportation |
| 8 | | Stores Equipment |

| | |
|---|---|
| **Less:** *Fully Allocated Depreciation* | |
| Transportation | |
| Stores Equipment | |
| **Net Depreciation** | -$ 2,751,106 |

***Notes:***

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

## Appendix 2-BA
## Fixed Asset Continuity Schedule 2017

**Accounting Standard** USGAAP
**Year** 2017

| | | | Cost | | | | Accumulated Depreciation | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **CCA Class** | **OEB** | **Description** | **Opening Balance** | **Additions** | **Disposals** | **Closing Balance** | **Opening Balance** | **Additions** | **Disposals** | **Closing Balance** | **Net Book Value** |
| 12 | 1611 | Computer Software (Formally known as Account 1925) | | | | | | | | | |
| CEC | 1612 | Land Rights (Formally known as Account 1906) | | | | | | | | | |
| N/A | 1615 | Land | $ 407,800 | $ - | $ - | $ 407,800 | -$ 407,800 | $ - | $ - | -$ 407,800 | $ - |
| 1 | 1620 | Buildings &Fixtures | $ 5,561,856 | $ 13,760 | $ - | $ 5,575,616 | -$ 2,210,955 | -$ 140,158 | $ - | -$ 2,351,113 | $ 3,224,503 |
| 17 | 1650 | Reservoirs Dams & Water | $ 670,778 | $ 206,000 | $ - | $ 876,778 | -$ 670,778 | -$ 29,429 | $ - | -$ 700,207 | $ 176,571 |
| 17 | 1665 | Fuel Holders Produce | $ 7,352,566 | $ 663,960 | $ - | $ 8,016,526 | -$ 850,891 | -$ 212,862 | $ - | -$ 1,063,753 | $ 6,952,773 |
| 17 | 1670 | Prime Movers | $ 16,465,338 | $ 293,963 | -$ 117,985 | $ 16,641,316 | -$ 10,356,808 | -$ 1,145,586 | $ 117,585 | -$ 11,384,809 | $ 5,256,507 |
| 17 | 1675 | Generators | $ 8,556,830 | $ 139,268 | -$ 48,744 | $ 8,647,354 | -$ 3,491,931 | -$ 402,004 | $ 48,744 | -$ 3,845,191 | $ 4,802,163 |
| 17 | 1680 | Accessory Electc Equ | $ 2,775,316 | $ 275,300 | $ - | $ 3,050,616 | -$ 1,247,070 | -$ 158,465 | $ - | -$ 1,405,535 | $ 1,645,081 |
| 17 | 1685 | Misc Power Plant Equ | $ 4,203,502 | $ 244,400 | $ - | $ 4,447,902 | -$ 2,255,662 | -$ 131,722 | $ - | -$ 2,387,384 | $ 2,060,518 |
| N/A | 1805 | Land | $ 294,456 | $ - | $ - | $ 294,456 | -$ 112,755 | -$ 5,712 | $ - | -$ 118,467 | $ 175,989 |
| 14.1 | 1806 | L&Rights | $ 234,126 | $ - | $ - | $ 234,126 | -$ 69,719 | -$ 2,271 | $ - | -$ 71,990 | $ 162,136 |
| 47 | 1808 | Buildings | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | 1810 | Leasehold Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1815 | Transformer Station Equipment >50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1820 | Distribution Station Equipment <50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1825 | Storage Battery Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1830 | Poles, Towers & Fixtures | $ 3,128,096 | $ 331,289 | -$ 19,877 | $ 3,439,508 | -$ 523,697 | -$ 58,452 | $ 19,877 | -$ 562,272 | $ 2,877,236 |
| 47 | 1835 | Overhead Conductors & Devices | $ 2,254,133 | $ 236,538 | -$ 37,846 | $ 2,452,825 | -$ 456,875 | -$ 45,582 | $ 37,846 | -$ 464,611 | $ 1,988,214 |
| 47 | 1840 | Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1845 | Underground Conductors & Devices | $ 292,362 | $ - | $ - | $ 292,362 | -$ 144,752 | -$ 7,701 | $ - | -$ 152,453 | $ 139,909 |
| 47 | 1850 | Line Transformers | $ 2,243,007 | $ 152,081 | -$ 9,125 | $ 2,385,963 | -$ 668,657 | -$ 55,779 | $ 9,125 | -$ 715,311 | $ 1,670,652 |
| 47 | 1855 | Services (Overhead & Underground) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1860 | Meters | $ 651,563 | $ 56,487 | -$ 3,389 | $ 704,661 | -$ 257,753 | -$ 43,756 | $ 3,389 | -$ 298,120 | $ 406,541 |
| 47 | 1860 | Meters (Smart Meters) | $ - | | | $ - | $ - | | | $ - | $ - |
| N/A | 1905 | Land | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 1 & 3 | 1908 | Buildings & Fixtures | $ 11,089,514 | $ 818,452 | $ - | $ 11,907,966 | -$ 2,076,568 | -$ 225,375 | $ - | -$ 2,301,943 | $ 9,606,023 |
| 13 | 1910 | Leasehold Improvements | $ 115,183 | $ - | $ - | $ 115,183 | -$ 54,340 | -$ 12,993 | $ - | -$ 67,333 | $ 47,850 |
| 8 | 1915-A | Office Furniture & Equipment (10 years) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1915 | Office Furniture & Equipment (5 & 7 years) | $ 75,425 | $ 17,500 | -$ 23,956 | $ 68,969 | -$ 49,132 | -$ 8,998 | $ 23,956 | -$ 34,174 | $ 34,795 |
| 10 | 1920-A | Computer Equipment - Hardware | $ - | | | $ - | $ - | | | $ - | $ - |
| 45 | 1920-B | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | | | $ - | $ - | | | $ - | $ - |
| 50 | 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 27,714 | $ 8,750 | -$ 15,334 | $ 21,130 | -$ 26,476 | -$ 1,238 | $ 15,334 | -$ 12,380 | $ 8,750 |
| 10 | 1930 | Transportation Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1935 | Stores Equipment | $ 145,577 | $ 26,250 | -$ 5,417 | $ 166,410 | -$ 98,072 | -$ 17,859 | $ 5,417 | -$ 110,514 | $ 55,896 |
| 8 | 1940 | Tools, Shop & Garage Equipment | $ 122,245 | $ - | -$ 25,809 | $ 96,436 | -$ 56,988 | -$ 17,544 | $ 25,809 | -$ 48,723 | $ 47,713 |
| 8 | 1945 | Measurement & Testing Equipment | $ 121,887 | $ 21,000 | -$ 35,160 | $ 107,727 | -$ 85,338 | -$ 21,634 | $ 35,160 | -$ 71,812 | $ 35,915 |
| 8 | 1950 | Power Operated Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1955 | Communications Equipment | $ 20,332 | $ - | $ - | $ 20,332 | -$ 28,807 | -$ 687 | $ - | -$ 29,494 | -$ 9,162 |
| 8 | 1955 | Communication Equipment (Smart Meters) | $ - | | | $ - | $ - | | | $ - | $ - |
| 8 | 1960 | Miscellaneous Equipment | $ 722,677 | $ 101,500 | -$ 131,671 | $ 692,506 | -$ 360,169 | -$ 131,056 | $ 131,671 | -$ 359,554 | $ 332,952 |
| 47 | 1975 | Load Management Controls Utility Premises | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1980 | System Supervisor Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1985 | Miscellaneous Fixed Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1995 | Contributions & Grants | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| N/A | A | Maj Rollup Acc Dep Suspense | $ - | $ - | $ - | $ - | -$ 240,316 | $ - | $ - | -$ 240,316 | -$ 240,316 |
| N/A | B | Acc Dep - Contra for Group Retirement | $ - | $ - | $ - | $ - | $ 172,061 | $ - | $ - | $ 172,061 | $ 172,061 |
| N/A | C | Suspense/Conversion/Error | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| - | etc. | | | | | | | | | | |
| - | | | | | | | | | | | |
| - | | **Total** | **$ 67,532,283** | **$ 3,606,498** | **-$ 474,313** | **$ 70,664,468** | **-$ 26,630,248** | **-$ 2,876,863** | **$ 473,913** | **-$ 29,033,198** | **$ 41,631,270** |

| | | |
|---|---|---|
| 10 | | Transportation |
| 8 | | Stores Equipment |

**Less:** *Fully Allocated Depreciation*

| | |
|---|---|
| Transportation | |
| Stores Equipment | |
| **Net Depreciation** | -$ 2,876,863 |

***Notes:***

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

## Appendix 2-BA
## Fixed Asset Continuity Schedule 2018

| | |
|---|---|
| Accounting Standard | USGAAP |
| Year | 2018 |

| | | | Cost | | | | Accumulated Depreciation | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| CCA Class | OEB | Description | Opening Balance | Additions | Disposals | Closing Balance | Opening Balance | Additions | Disposals | Closing Balance | Net Book Value |
| 12 | 1611 | Computer Software (Formally known as Account 1925) | | | | | | | | | |
| CEC | 1612 | Land Rights (Formally known as Account 1906) | | | | | | | | | |
| N/A | 1615 | Land | $ 407,800 | $ - | $ - | $ 407,800 | -$ 407,800 | $ - | $ - | -$ 407,800 | $ - |
| 1 | 1620 | Buildings &Fixtures | $ 5,575,616 | $ 17,280 | $ - | $ 5,592,896 | -$ 2,351,113 | -$ 140,590 | $ - | -$ 2,491,703 | $ 3,101,193 |
| 17 | 1650 | Reservoirs Dams & Water | $ 876,778 | $ - | $ - | $ 876,778 | -$ 700,207 | -$ 29,429 | $ - | -$ 729,636 | $ 147,142 |
| 17 | 1665 | Fuel Holders Produce | $ 8,016,526 | $ 103,680 | $ - | $ 8,120,206 | -$ 1,063,753 | -$ 223,494 | $ - | -$ 1,287,247 | $ 6,832,959 |
| 17 | 1670 | Prime Movers | $ 16,641,316 | $ 972,469 | -$ 388,868 | $ 17,224,917 | -$ 11,384,809 | -$ 1,143,573 | $ 388,868 | -$ 12,139,514 | $ 5,085,403 |
| 17 | 1675 | Generators | $ 8,647,354 | $ 375,896 | -$ 131,564 | $ 8,891,686 | -$ 3,845,191 | -$ 443,590 | $ 131,564 | -$ 4,157,217 | $ 4,734,469 |
| 17 | 1680 | Accessory Electc Equ | $ 3,050,616 | $ 545,400 | $ - | $ 3,596,016 | -$ 1,405,535 | -$ 180,788 | $ - | -$ 1,586,323 | $ 2,009,693 |
| 17 | 1685 | Misc Power Plant Equ | $ 4,447,902 | $ 86,400 | $ - | $ 4,534,302 | -$ 2,387,384 | -$ 135,336 | $ - | -$ 2,522,720 | $ 2,011,582 |
| N/A | 1805 | Land | $ 294,456 | $ - | $ - | $ 294,456 | -$ 118,467 | -$ 5,712 | $ - | -$ 124,179 | $ 170,277 |
| 14.1 | 1806 | L&Rights | $ 234,126 | $ - | $ - | $ 234,126 | -$ 71,990 | -$ 2,271 | $ - | -$ 74,261 | $ 159,865 |
| 47 | 1808 | Buildings | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | 1810 | Leasehold Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1815 | Transformer Station Equipment >50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1820 | Distribution Station Equipment <50 kV | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1825 | Storage Battery Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1830 | Poles, Towers & Fixtures | $ 3,439,508 | $ 205,620 | -$ 12,337 | $ 3,632,791 | -$ 562,272 | -$ 63,120 | $ 12,337 | -$ 613,055 | $ 3,019,736 |
| 47 | 1835 | Overhead Conductors & Devices | $ 2,452,825 | $ 143,934 | -$ 23,029 | $ 2,573,730 | -$ 464,611 | -$ 49,044 | $ 23,029 | -$ 490,626 | $ 2,083,104 |
| 47 | 1840 | Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1845 | Underground Conductors & Devices | $ 292,362 | $ - | $ - | $ 292,362 | -$ 152,453 | -$ 7,701 | $ - | -$ 160,154 | $ 132,208 |
| 47 | 1850 | Line Transformers | $ 2,385,963 | $ 112,726 | -$ 6,764 | $ 2,491,925 | -$ 715,311 | -$ 58,888 | $ 6,764 | -$ 767,435 | $ 1,724,490 |
| 47 | 1855 | Services (Overhead & Underground) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1860 | Meters | $ 704,661 | $ 51,040 | -$ 3,062 | $ 752,639 | -$ 298,120 | -$ 47,046 | $ 3,062 | -$ 342,104 | $ 410,535 |
| 47 | 1860 | Meters (Smart Meters) | $ - | | | $ - | $ - | | | $ - | $ - |
| N/A | 1905 | Land | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 1 & 3 | 1908 | Buildings & Fixtures | $ 11,907,966 | $ 407,100 | $ - | $ 12,315,066 | -$ 2,301,943 | -$ 237,386 | $ - | -$ 2,539,329 | $ 9,775,737 |
| 13 | 1910 | Leasehold Improvements | $ 115,183 | $ - | $ - | $ 115,183 | -$ 67,333 | -$ 12,993 | $ - | -$ 80,326 | $ 34,857 |
| 8 | 1915-A | Office Furniture & Equipment (10 years) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1915 | Office Furniture & Equipment (5 & 7 years) | $ 68,969 | $ 17,500 | $ - | $ 86,469 | -$ 34,174 | -$ 7,646 | $ - | -$ 41,820 | $ 44,649 |
| 10 | 1920-A | Computer Equipment - Hardware | $ - | | | $ - | $ - | | | $ - | $ - |
| 45.0 | 1920-B | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | | | $ - | $ - | | | $ - | $ - |
| 50 | 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 21,130 | $ 8,750 | -$ 12,381 | $ 17,499 | -$ 12,380 | $ - | $ 12,381 | $ 1 | $ 17,500 |
| 10 | 1930 | Transportation Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1935 | Stores Equipment | $ 166,410 | $ 26,250 | -$ 13,761 | $ 178,899 | -$ 110,514 | -$ 16,838 | $ 13,761 | -$ 113,591 | $ 65,308 |
| 8 | 1940 | Tools, Shop & Garage Equipment | $ 96,436 | $ - | -$ 7,654 | $ 88,782 | -$ 48,723 | -$ 14,625 | $ 7,654 | -$ 55,694 | $ 33,088 |
| 8 | 1945 | Measurement & Testing Equipment | $ 107,727 | $ 21,000 | -$ 57,030 | $ 71,697 | -$ 71,812 | -$ 14,917 | $ 57,030 | -$ 29,699 | $ 41,998 |
| 8 | 1950 | Power Operated Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | 1955 | Communications Equipment | $ 20,332 | $ - | $ - | $ 20,332 | -$ 29,494 | -$ 687 | $ - | -$ 30,181 | -$ 9,849 |
| 8 | 1955 | Communication Equipment (Smart Meters) | $ - | | | $ - | $ - | | | $ - | $ - |
| 8 | 1960 | Miscellaneous Equipment | $ 692,506 | $ 101,500 | -$ 136,214 | $ 657,792 | -$ 359,554 | -$ 105,872 | $ 136,214 | -$ 329,212 | $ 328,580 |
| 47 | 1975 | Load Management Controls Utility Premises | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1980 | System Supervisor Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1985 | Miscellaneous Fixed Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 47 | 1995 | Contributions & Grants | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| N/A | A | Maj Rollup Acc Dep Suspense | | $ - | $ - | | -$ 240,316 | $ - | $ - | -$ 240,316 | -$ 240,316 |
| N/A | B | Acc Dep - Contra for Group Retirement | | $ - | $ - | | $ 172,061 | $ - | $ - | $ 172,061 | $ 172,061 |
| N/A | C | Suspense/Conversion/Error | | $ - | $ - | | | $ - | $ - | | |
| - | etc. | | | | | | | | | | |
| - | | | | | | | | | | | |
| - | | **Total** | **$ 70,664,468** | **$ 3,196,545** | **-$ 792,664** | **$ 73,068,349** | **-$ 29,033,198** | **-$ 2,941,546** | **$ 792,664** | **-$ 31,182,080** | **$ 41,886,269** |

| | | |
|---|---|---|
| 10 | | Transportation |
| 8 | | Stores Equipment |

| | |
|---|---|
| **Less:** *Fully Allocated Depreciation* | |
| Transportation | |
| Stores Equipment | |
| **Net Depreciation** | -$ 2,941,546 |

***Notes:***

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

# Appendix 2-AA
## Capital Projects Table 2013 to 2018

| Projects | 2013 | 2014 | 2015 | 2016 | 2017 Bridge Year | 2018 Test Year |
|---|---|---|---|---|---|---|
| **Reporting Basis** | **USGAAP** | **USGAAP** | **USGAAP** | **USGAAP** | **USGAAP** | **USGAAP** |
| **SYSTEM ACCESS** | | | | | | |
| **New Customer Connections & Service Upgrades** | | | | | | |
| New Customer Connections & Service Upgrades | 476,769 | 437,463 | 559,417 | 342,050 | 629,000 | 658,000 |
| Contributions and Removals | -366,714 | -432,709 | -554,582 | -319,848 | -629,000 | -658,000 |
| New Customer Connections & Service Upgrades Sub-total | 110,055 | 4,754 | 4,835 | 22,203 | 0 | 0 |
| **Service Cancellations** | | | | | | |
| Service Cancellations | 69,159 | 85,619 | 132,573 | 87,225 | 141,000 | 148,000 |
| Removals | -69,159 | -85,619 | -132,573 | -87,225 | -141,000 | -148,000 |
| Service Cancellations Sub-Total | 0 | 0 | 0 | 0 | 0 | 0 |
| **Fixed Price Layouts** | | | | | | |
| Fixed Price Layouts | 51,416 | 81,995 | 107,914 | 104,411 | 102,000 | 106,000 |
| Contributions and Removals | -38,562 | -55,984 | -70,342 | -56,701 | -102,000 | -106,000 |
| Fixed Price Layouts Sub-Total | 12,855 | 26,011 | 37,572 | 47,710 | 0 | 0 |
| **SYSTEM ACCESS Sub-Total** | **122,909** | **30,765** | **42,407** | **69,913** | **0** | **0** |
| | | | | | | |
| **SYSTEM RENEWAL** | | | | | | |
| **Distribution** | | | | | | |
| Distribution System Improvements | 1,217,313 | 542,615 | 583,521 | 817,470 | 610,000 | 636,000 |
| Contributions and Removals | -520,333 | -202,504 | -125,943 | -125,856 | -207,200 | -216,320 |
| Distribution Sub-Total | 696,980 | 340,111 | 457,578 | 691,615 | 402,800 | 419,680 |
| **Metering & Minor Storm Damage** | | | | | | |
| Metering & Minor Storm Damage | 71,797 | 174,012 | 97,563 | 77,201 | 112,000 | 116,000 |
| Removals | -8,461 | -20,634 | -11,447 | -9,102 | -13,440 | -13,920 |
| Metering & Minor Storm Damage Sub-Total | 63,336 | 153,378 | 86,116 | 68,100 | 98,560 | 102,080 |
| **Damage Claims & Small External Demand Requests** | | | | | | |
| Damage Claims & Small External Demand Requests | 6,642 | 17,746 | 0 | 0 | 20,000 | 20,000 |
| Contributions and Removals | -6,642 | -11,663 | 0 | 0 | -20,000 | -20,000 |
| Damage Claims & Small External Demand Requests Sub-Total | 0 | 6,082 | 0 | 0 | 0 | 0 |
| **Return Used Transformers to Inventory** | | | | | | |
| Return Used Transformers to Inventory | -4,459 | 4,459 | 0 | 0 | 0 | 0 |
| Return Used Transformers to Inventory Sub-Total | -4,459 | 4,459 | 0 | 0 | 0 | 0 |
| **Generation** | | | | | | |
| **Engine Replacements** | | | | | | |
| Engine Replacements | 0 | 0 | 0 | 0 | 0 | 767,000 |
| Big Trout A Replacement | 0 | 0 | 0 | 0 | 0 | 0 |
| Big Trout B Replacement | 86,957 | 0 | 0 | 0 | 0 | 0 |
| Bearskin Replacement | 4,499 | 31,592 | 54,338 | 886,961 | 0 | 0 |
| Bisco Replacement | 367,075 | 0 | 0 | 0 | 0 | 0 |
| Deer Lake Replacements | 159,521 | 0 | 0 | 902,931 | 0 | 0 |
| Fort Severn Replacements | 0 | 13,521 | -204,952 | 0 | 0 | 0 |
| Hillsport Replacements | 152,749 | 0 | 0 | 0 | 0 | 0 |
| Lansdowne Replacements | 9,438 | 1,483,547 | 233,357 | 0 | 0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Marten Falls Replacements | 3,570 | 8,962 | 8,602 | -214,285 | 0 | 0 |
| Oba Replacement | 481,906 | 0 | 0 | 0 | 0 | 0 |
| Sachigo Replacement | 709,387 | 50,898 | 0 | 0 | 0 | 0 |
| Sandy Lake Replacements | 16,032 | 1,630 | 0 | 0 | 0 | 0 |
| Wapakeka Replacements | -183,954 | 9,416 | -226,297 | 0 | 0 | -76,700 |
| Removals | 0 | -358,538 | 218,994 | -224,465 | 0 | 0 |
| Engine Replacements Sub-Total | 1,807,181 | 1,241,028 | 84,043 | 1,351,143 | 0 | 690,300 |
| **Engine Overhauls** | | | | | | |
| Engine Overhauls | 0 | 0 | 0 | 0 | 670,000 | 675,000 |
| Armstrong Overhauls | 0 | 0 | 223,259 | 2,173 | 0 | 0 |
| Bearskin Overhauls | 125,921 | 0 | 0 | 0 | 0 | 0 |
| Big Trout Lake Overhauls | 0 | 401,690 | 121,239 | 0 | 0 | 0 |
| Deer Lake Overhauls | 352,211 | 261,391 | 760 | 0 | 0 | 0 |
| Gull Bay Overhauls | 0 | 0 | 68,415 | 0 | 0 | 0 |
| Hillsport Overhauls | 0 | 0 | 0 | 51,570 | 0 | 0 |
| Kingfisher Overhauls | 108,899 | 0 | 0 | 0 | 0 | 0 |
| Sachigo Overhauls | 0 | 0 | 119,299 | -7,615 | 0 | 0 |
| Sandy Lake Overhauls | 0 | 0 | 0 | 644,527 | 0 | 0 |
| Wapekeka Overhauls | 0 | 0 | 221,967 | 0 | 0 | 0 |
| Weagamow Overhauls | 122,739 | 0 | 0 | 0 | 0 | 0 |
| Removals | -58,072 | -65,632 | -74,990 | 0 | -67,000 | -67,500 |
| Engine Overhauls Sub-Total | 651,698 | 597,449 | 679,948 | 690,654 | 603,000 | 607,500 |
| **Fuel Tank Replacements and Diesel Civil Improvements** | | | | | | |
| Diesel Plant Civil Improvements | 133,312 | 411,512 | 250,487 | 211,340 | 344,000 | 346,000 |
| Hillsport Kiosk | 0 | 0 | 0 | 0 | 224,000 | 0 |
| Hillsport Bulk Tank | 0 | 0 | 0 | 0 | 388,000 | 0 |
| Deer Lake Remote Switch | 16,478 | 13,533 | 0 | 0 | 0 | 0 |
| DGS Day Tank Replacements | 0 | 1,044,029 | 0 | 0 | 0 | 0 |
| Fuel System Improvements | 690,907 | 8,114 | 0 | 0 | 0 | 0 |
| Gx Development work, VCC upgrade, Switchgear, OCE | 136,674 | 0 | 0 | 0 | 0 | 0 |
| Fuel Tank Replacments, Civil Plant Improve Sub-Total | 977,370 | 1,477,188 | 250,487 | 211,340 | 956,000 | 346,000 |
| **Renewable Energy Technology** | | | | | | |
| Wind Turbine | 92,584 | 94,309 | 88 | 0 | 0 | 0 |
| Hydel | 211,069 | 250,150 | 301,615 | 181,219 | 169,000 | 0 |
| Removals | -7,913 | -24,713 | -28,649 | 0 | 0 | 0 |
| Renewable Energy Technology Sub-Total | 295,741 | 319,746 | 273,053 | 181,219 | 169,000 | 0 |
| **SYSTEM RENEWAL Sub-Total** | **4,487,848** | **4,139,442** | **1,831,225** | **3,194,071** | **2,229,360** | **2,165,560** |
| | | | | | | |
| **SYSTEM SERVICE** | | | | | | |
| **Generator Upgrades** | | | | | | |
| Big Trout Lake-Wapekeka Upgrade & Connection | 1,097 | 3,926 | 34,320 | 137,242 | 996,000 | 2,149,000 |
| Deer Lake | 0 | 130,152 | 2,074,328 | 101,888 | 0 | 0 |
| Fort Severn | 3,276 | 145,372 | 3,002,420 | 17,407 | 0 | 0 |
| Kingfisher Lake | 390 | 8,974 | 39,753 | 235,771 | 4,990,000 | 0 |
| Sandy Lake | 0 | 0 | 0 | 0 | 0 | 367,000 |
| Weagamow | 443 | 0 | 13,871 | 1,815,758 | 1,485,000 | 0 |
| Kasabonika | 38,400 | 68,885 | 760,675 | 280,360 | 0 | 0 |
| Wapekeka | 0 | 21,960 | 1,128,674 | 0 | 0 | 2,832,000 |
| Capital Contribution & Removals | -42,668 | -360,500 | -7,072,809 | -2,588,426 | -7,471,000 | -5,348,000 |
| Generator Upgrades Sub-Total | 939 | 18,768 | -18,768 | 0 | 0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Controls/SCADA Upgrades** | | | | | | |
| SCADA & PLC Replacements & High Speed Internet | 124,411 | -232,175 | 0 | 0 | 413,000 | 505,000 |
| Controls/SCADA Upgrades Sub-Total | 124,411 | -232,175 | 0 | 0 | 413,000 | 505,000 |
| **SYSTEM SERVICE Sub-Total** | **125,350** | **-213,407** | **-18,768** | **0** | **413,000** | **505,000** |
| | | | | | | |
| **General Plant** | | | | | | |
| **General Plant** | | | | | | |
| Staff houses | 0 | 301,134 | 14,920 | 416,849 | 344,000 | 164,000 |
| Garages | 180,865 | 118,380 | 175,706 | 387,156 | 342,000 | 0 |
| Water Wells | 128,784 | 67,370 | 0 | 0 | 0 | 0 |
| Other | 166,607 | 3,294 | 0 | 0 | 224,000 | 226,000 |
| Minor Fixed Assets | 214,468 | 187,314 | 282,092 | 110,187 | 175,000 | 175,000 |
| General Plant Sub-Total | 690,724 | 677,492 | 472,718 | 914,193 | 1,085,000 | 565,000 |
| **GENERAL PLANT Sub-Total** | **690,724** | **677,492** | **472,718** | **914,193** | **1,085,000** | **565,000** |
| **Miscellaneous** | | | | | | |
| **Total** | **5,426,832** | **4,634,292** | **2,327,582** | **4,178,177** | **3,727,360** | **3,235,560** |
| **Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*** | | | | | | |
| **Total** | **5,426,832** | **4,634,292** | **2,327,582** | **4,178,177** | **3,727,360** | **3,235,560** |

***Notes:***

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

## Appendix 2-AB
## Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

**First year of Forecast Period:** *2018*

| CATEGORY | Historical Period (previous plan[1] & actual) | | | | | | | | | | | | | | | Forecast Period (planned) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | | | 2014 | | | 2015 | | | 2016 | | | 2017 | | | 2018 | 2019 | 2020 | 2021 | 2022 |
| | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual[2] | Var | | | | | |
| | *$ '000* | | % | *$ '000* | | % | *$ '000* | | % | *$ '000* | | % | *$ '000* | | | *$ '000* | | | | |
| **System Access** | - | 123 | -- | - | 31 | -- | - | 42 | -- | - | 70 | -- | - | | -- | - | - | - | - | - |
| **System Renewal - Distribution** | 698 | 756 | 8.3% | 585 | 504 | -13.9% | 518 | 544 | 5.0% | 519 | 760 | 46.4% | 501 | | -100.0% | 522 | 609 | 643 | 654 | 670 |
| **System Renewal - Generation** | 4,771 | 3,401 | -28.7% | 4,822 | 3,615 | -25.0% | 2,888 | 1,288 | -55.4% | 3,339 | 2,434 | -27.1% | 1,728 | | -100.0% | 1,644 | 2,636 | 3,369 | 3,791 | 2,221 |
| **System Service - Generation** | 1,177 | 456 | -61.3% | 604 | - 193 | -132.1% | 1,171 | - 19 | -101.6% | 399 | - | -100.0% | 413 | | -100.0% | 505 | 726 | 675 | 391 | 848 |
| **General Plant** | 1,101 | 691 | -37.2% | 824 | 677 | -17.8% | 1,481 | 473 | -68.1% | 803 | 914 | 13.8% | 1,085 | | -100.0% | 565 | 572 | 581 | 590 | 598 |
| **TOTAL EXPENDITURE** | 7,747 | 5,427 | -29.9% | 6,834 | 4,634 | -32.2% | 6,058 | 2,328 | -61.6% | 5,060 | 4,178 | -17.4% | 3,727 | - | -100.0% | 3,236 | 4,543 | 5,268 | 5,425 | 4,337 |
| **System O&M** | $ 18,662 | $18,335 | -1.8% | $18,092 | $18,601 | 2.8% | $20,644 | $16,492 | -20.1% | $21,463 | $18,060 | -15.9% | $20,760 | | -100.0% | $21,291 | $22,260 | $23,650 | $24,095 | $24,281 |

**Notes to the Table:**

1. Historical “previous plan” data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' ye 0

| Explanatory Notes on Variances (complete only if applicable) |
|---|
| **Notes on shifts in forecast vs. historical budgets by category** |
| |
| **Notes on year over year Plan vs. Actual variances for Total Expenditures** |
| |
| **Notes on Plan vs. Actual variance trends for individual expenditure categories** |
| |

**HYDRO ONE REMOTE COMMUNITIES INC.**
**Comparison of Net Capital Expenditures - Historic, Bridge and Test Years**
Year Ending December 31
($000s)

| | $000s 2013 | 2014 | 2015 | 2016 | Bridge 2017 | Test 2018 |
|---|---|---|---|---|---|---|
| **Generation** | | | | | | |
| Planned Capital Replacements & Overhauls of Diesel Engines & Aux Equipm | 2,460 | 1,837 | 765 | 2,042 | 603 | 1,297 |
| Station Upgrade Projects | 1 | 19 | (19) | 0 | 0 | 0 |
| Fuel Tank Farm Upgrade Projects | 707 | 1,066 | 0 | 0 | 612 | 0 |
| Renewable Energy Technology | 432 | 320 | 273 | 181 | 169 | 0 |
| Station Controls | 124 | (232) | 0 | 0 | 413 | 505 |
| Plant and Site Improvements | 133 | 412 | 250 | 211 | 344 | 346 |
| **Total "Generation"** | **3,857** | **3,422** | **1,269** | **2,434** | **2,141** | **2,148** |
| **Distribution** | | | | | | |
| Metering, Minor Storm Damage & Damage Claims | 59 | 164 | 86 | 68 | 99 | 102 |
| Fixed Price Layouts, New Customer Connections & Service Upgrades | 123 | 31 | 42 | 70 | 0 | 0 |
| Distribution System Improvements | 697 | 340 | 458 | 692 | 403 | 420 |
| **Total " Distribution"** | **879** | **535** | **586** | **830** | **502** | **522** |
| **Facilities** | | | | | | |
| Planned Capital Call-Up/Replace Powerhouse, Staffhouse, Outbuildings & Service Centre | 476 | 490 | 191 | 804 | 910 | 390 |
| **Total "Facilities"** | **476** | **490** | **191** | **804** | **910** | **390** |
| **Minor Fixed Assets** | 214 | 187 | 282 | 110 | 175 | 175 |
| **Overall Total** | **214** | **187** | **282** | **110** | **175** | **175** |
| **TOTAL REMOTES CAPITAL** | **5,426** | **4,634** | **2,328** | **4,178** | **3,728** | **3,235** |

Notes:

Upgrade expenditures fully recoverable
Generation Improvement Capital include non-routine projects
New customer connections budgeted as fully recoverable in bridge and test year(s)
Planned capital replacement of diesel engines include capital overhauls

**HYDRO ONE REMOTE COMMUNITIES INC.**
**Continuity of Property, Plant and Equipment**
Year Ending December 31
Historical (2013-2016), Bridge (2017) & Test (2018) Years
Total - Gross Balances
($000s)

**Fixed Assets**

| Line No. | Year | Opening Balance | Additions | Retirements | Sales | Transfers In/Out | Adjustment | Closing Balance | Average |
|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| **Historic** | | | | | | | | | |
| 1 | 2013 | 54,790 | 9,204 | (5,085) | (4) | | | 58,905 | 56,848 |
| 2 | 2014 | 58,905 | 5,970 | (1,265) | (9) | | | 63,601 | 61,253 |
| 3 | 2015 | 63,601 | 3,278 | (1,506) | - | | | 65,373 | 64,487 |
| 4 | 2016 | 65,373 | 4,656 | (1,914) | (1) | | (582) | 67,532 | 66,453 |
| **Bridge** | | | | | | | | | |
| 5 | 2017 | 67,532 | 3,606 | (474) | | | | 70,664 | 69,098 |
| **Test** | | | | | | | | | |
| 6 | 2018 | 70,664 | 3,197 | (793) | | | | 73,068 | 71,866 |

Notes:

Property Plant and Equipment balances do not include inventory held as "Future Use Assets"

**HYDRO ONE REMOTE COMMUNITIES INC.**
**Continuity Accumulated Depreciation**
Year Ending December 31
Historical (2013-2016), Bridge (2017) & Test (2018) Years
Total - Gross Balances
($000s)

**Fixed Assets**

| Line No. | Year | Opening Balance | Additions | Retirements | Sales | Transfers In/Out | Other | Closing Balance | Average |
|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| **Historic** | | | | | | | | | |
| 1 | 2013 | 25,779 | 2,563 | (5,083) | (2) | | | 23,257 | 24,518 |
| 2 | 2014 | 23,257 | 2,594 | (1,265) | 2 | | | 24,588 | 23,923 |
| 3 | 2015 | 24,588 | 2,711 | (1,506) | - | | | 25,793 | 25,191 |
| 4 | 2016 | 25,793 | 2,751 | (1,914) | - | | | 26,630 | 26,212 |
| **Bridge** | | | | | | | | | |
| 5 | 2017 | 26,630 | 2,877 | (474) | - | - | | 29,033 | 27,832 |
| **Test** | | | | | | | | | |
| 6 | 2018 | 29,033 | 2,942 | (793) | - | - | | 31,182 | 30,108 |

**HYDRO ONE REMOTE COMMUNITIES INC.**
**Continuity of Construction Work in Progress**
Year Ending December 31
Historical (2013-2016), Bridge (2017) & Test (2018) Years
Total - Gross Balances
($000s)

**Fixed Assets**

| Line No. | | Year | Opening Balance | Capital Expenditures | Transfers to Plant | Other Adjustments | Closing Balance |
|---|---|---|---|---|---|---|---|
| | | | (a) | (b) | (c) | (d) | (e) |
| | **Historic** | | | | | | |
| 1 | | 2013 | 7,250 | 5,212 | (8,989) | | 3,473 |
| 2 | | 2014 | 3,473 | 4,447 | (5,782) | | 2,138 |
| 3 | | 2015 | 2,138 | 2,046 | (2,996) | | 1,188 |
| 4 | | 2016 | 1,188 | 4,068 | (4,546) | | 710 |
| | **Bridge** | | | | | | |
| 5 | | 2017 | 710 | 3,553 | (3,431) | | 832 |
| | **Test** | | | | | | |
| 6 | | 2018 | 832 | 3,060 | (3,021) | | 871 |

**HYDRO ONE REMOTE COMMUNITIES INC.**
**Statement of Working Capital**
Test Year (2018)
($000s)

| Line No. | Particulars | | 2018 |
|---|---|---|---|
| | OM&A Expenses | | |
| 1 | Generation | $ | 44,159 |
| 2 | Distribution | | 2,203 |
| 3 | Billing and Collecting | | 1,999 |
| 4 | Community Relations | | 305 |
| 5 | Administrative & General | | 1,342 |
| 6 | External Costs | | 135 |
| 7 | Total Eligible OM&A | $ | 50,143 |
| 8 | Working Capital Factor | | 7.5% |
| 9 | **Working Capital Allowance** | **$** | **3,761** |

**HYDRO ONE REMOTE COMMUNITIES INC**

Mapping In-Service Additions to Grouped USofA Accounts

Year Ending December 31

Historical (2013, 2014, 2015 and 2016), Bridge (2017) & Test (2018) Years

($000s)

| | | | Historical | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Minimum USoA Grouping** | **Account Numbers** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| 1 | Land and Buildings | 1805, 1806, 1808, 1810, 1905, 1906 | - | - | - | - | - | - |
| 2 | TS Primary Above 50 | 1815 | - | - | - | - | - | - |
| 3 | Distribution Station Equipment | 1820 | - | - | - | - | - | - |
| 4 | Poles, Wires | 1830, 1835, 1840, 1845 | 399 | 822 | 219 | 517 | 568 | 350 |
| 5 | Line Transformers | 1850 | 95 | 201 | 120 | 75 | 152 | 113 |
| 6 | Services and Meters | 1855, 1860 | 214 | 40 | 34 | 74 | 56 | 51 |
| 7 | General Plant | 1908, 1910 | 572 | 416 | 438 | 801 | 818 | 407 |
| 8 | Equipment | 1915, 1930, 1935, 1940, 1945, 1950, 1955, | 214 | 187 | 282 | 110 | 166 | 166 |
| 9 | IT Assets | 1920, 1925 | - | - | - | - | 9 | 9 |
| 10 | Generation Plant | 1615, 1620, 1650, 1665, 1670,1675, 1680, 1685, 1970, 1975, 1980, 2005 | 7,710 | 4,304 | 2,185 | 3,079 | 1,837 | 2,101 |
| 11 | Smart Meters | | | | | | | |
| 12 | **Total In-Service Additions** | | **9,204** | **5,970** | **3,278** | **4,656** | **3,606** | **3,197** |

## Appendix 2-D
## Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

| OM&A Before Capitalization | 2013 Historical Year | 2014 Historical Year | 2015 Historical Year | 2016 Historical Year | 2017 Bridge Year | 2018 Test Year |
|---|---|---|---|---|---|---|
| Generation Expenses Operations | $ 29,874 | $ 30,129 | $ 27,587 | $ 28,088 | $ 31,304 | $ 32,519 |
| Generation Expenses Maintenance | $ 8,648 | $ 9,932 | $ 8,610 | $ 9,574 | $ 11,392 | $ 11,640 |
| Other Power Supply Expenses | $ - | $ - | $ - | $ - | $ - | $ - |
| Distribution Expense Operations | $ 62 | $ 80 | $ 199 | $ 212 | $ 111 | $ 116 |
| Distribution Expense Maintenance | $ 1,399 | $ 1,799 | $ 2,216 | $ 1,780 | $ 2,008 | $ 2,087 |
| Collecting and Billing | $ 3,584 | $ 2,285 | $ 919 | $ 2,014 | $ 2,271 | $ 2,304 |
| Administration General Expenses | $ 1,715 | $ 1,833 | $ 1,822 | $ 1,846 | $ 1,675 | $ 1,739 |
| Other Deductions | $ 250 | $ 223 | $ 316 | $ 393 | $ 186 | $ 186 |
| | | | | | | |
| | | | | | | |
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| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| **Total OM&A Before Capitalization (B)** | $ 45,532 | $ 46,281 | $ 41,669 | $ 43,907 | $ 48,947 | $ 50,591 |

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

| Capitalized OM&A | 2013 Historical Year | 2014 Historical Year | 2015 Historical Year | 2016 Bridge Year | 2017 Test Year | 2018 Test Year | Directly Attributable? (Y/N) | Explanation for Change in Overhead Capitalized |
|---|---|---|---|---|---|---|---|---|
| Shared Services | $ 320 | $ 342 | $ 556 | $ 410 | $ 562 | $ 448 | Y | Directly attributable to total labour costs charged to capital |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
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| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| **Total Capitalized OM&A (A)** | $ 320 | $ 342 | $ 556 | $ 410 | $ 562 | $ 448 | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **% of Capitalized OM&A (=A/B)** | 1% | 1% | 1% | 1% | 1% | 1% | | |

**HYDRO ONE REMOTE COMMUNITIES INC.**
**Debt and Equity Summary**
Historical (2013, 2014, 2015, 2016), Bridge (2017), and Test (2018) Years
As at December 31
($000s)

| Particulars | Amount Outstanding 2013 Actual | Amount Outstanding 2014 Actual | Amount Outstanding 2015 Actual | Amount Outstanding 2016 Actual | Amount Outstanding 2017 Bridge Year | Amount Outstanding 2018 Test Year |
|---|---|---|---|---|---|---|
| Long-term debt | 23,000 | 33,000 | 33,000 | 43,000 | 43,000 | 43,000 |
| Short-term debt | 18,031 | 6,806 | 6,056 | - | 1,748 | 1,778 |
| Deemed long-term debt | - | - | - | - | (1,054) | (323) |
| Total rate base | **41,031** | **39,806** | **39,056** | **43,000** | **43,694** | **44,455** |

**HYDRO ONE REMOTES**

Cost of Long-Term Debt Capital
Test Year (2018)
Year ending December 31

| Line No. | Offering Date | Coupon Rate | Maturity Date | Principal Amount Offered ($Millions) | Premium Discount and Expenses ($Millions) | Net Capital Employed: Total Amount ($Millions) | Net Capital Employed: Per $100 Principal Amount (Dollars) | Effective Cost Rate | Total Amount Outstanding at 12/31/2017 ($Millions) | Total Amount Outstanding at 12/31/2018 ($Millions) | Avg. Monthly Averages ($Millions) | Carrying Cost ($Millions) | Projected Average Embedded Cost Rates |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
| 1 | 19-May-05 | 5.360% | 20-May-36 | 23.0 | 0.8 | 22.2 | 96.52 | 5.60% | 23.0 | 23.0 | 23.0 | 1.3 | |
| 2 | 6-Jun-14 | 4.170% | 3-Jun-44 | 10.0 | 0.1 | 9.9 | 99.40 | 4.21% | 10.0 | 10.0 | 10.0 | 0.4 | |
| 3 | 24-Feb-16 | 2.770% | 24-Feb-26 | 10.0 | 0.0 | 10.0 | 99.57 | 2.82% | 10.0 | 10.0 | 10.0 | 0.3 | |
| 4 | | **Total** | | | | | | | **43.0** | **43.0** | **43.0** | **2.0** | **4.63%** |

# COST OF SERVICE SUMMARY, COST DRIVERS AND SUMMARY OF OM&A EXPENDITURES

## 1.0 COST OF SERVICE SUMMARY

This evidence presents an overview of Remotes Cost of Service evidence. The Cost of Service submissions include the following components:

- Operation, Maintenance and Administration expenses;
- Depreciation and Amortization Expense;
- Payments in Lieu of Corporate Income Taxes; and
- External Costs.

Each of these components is separately addressed within the company's evidence. Exhibit reference numbers are provided below.

Remotes' forecast cost of service has been developed consistent with its corporate objectives. The Company's planning process is described in detail at Exhibit B1 and Exhibit A, Tab 7, Schedule 3.

### 1.1 Operation, Maintenance and Administration Expenses (OM&A)

Total OM&A expenses for the 2018 test year are $50,143K.

Remotes plans and organizes its OM&A expenses on the basis of the various work programs and functions performed by the company. Exhibits in support of OM&A costs have been prepared by program area, and appear within the submitted evidence as follows:

**Table 1**

**OM&A Cost Categories**

| **Program Areas** | **2018 Total Cost (in $K)** | **Reference** |
|---|---:|---|
| **Summary of OM&A Expenses** | **$50,143** | **Exhibit D1, Tab 1, Sch 1** |
| Generation | $44,159 | Exhibit D1, Tab 1, Sch 2 |
| Distribution | $2,203 | Exhibit D1, Tab 1, Sch 3 |
| Customer Care | $1,999 | Exhibit D1, Tab 1, Sch 4 |
| Community Relations | $305 | Exhibit D1, Tab 1, Sch 5 |
| Shared Services and Other Administrative Costs | $1,342 | Exhibit D1, Tab 1, Sch 6 |
| Cost of External Work | $135 | Exhibit D1, Tab 2, Sch 1 |

In order to satisfy the requirements of the *2006 Electricity Distribution Rate Handbook* and the *Filing Requirements for Transmission and Distribution Applications* (updated July 14, 2017) Exhibit D2, Tab 2, Schedule 1 identifies OM&A costs by grouped USofA accounts.

## 1.2 Resourcing

Labour costs are charged to OM&A and Capital work programs using standard labour rates. The evidence contained at Exhibit D2, Tab 5, Schedule 2 presents staff levels and costs incurred by the company. Exhibit D1, Tab 5, Schedule 1 describes standard labour rates.

### 1.3 Corporate Cost Allocation

Hydro One Networks Inc. provides common services to Distribution and Transmission and Hydro One Inc. subsidiaries, including Remotes, on a centralized and shared basis. The costs of these services and assets are assigned to business units on the basis of cost causation and benefit. These costs and assets are directly assigned where it is possible to do so.

In 2004, Black & Veatch ("B&V") was engaged by Hydro One to recommend a best practice methodology to distribute Common Corporate Costs to Hydro One and its subsidiaries and partnerships. The methodology is based on clearly articulated shared services and an established cost allocation approach based on cost causality and benefit principles. This Common Corporate Cost Allocation is supported by a recent B&V Review of Common Corporate Costs in 2015 prepared for Hydro One Networks Transmission (EB-2016-0160) and a later Review of Common Corporate Costs prepared for Hydro One Networks Distribution (EB-2017-0049).

The evidence included herein on the allocation of common corporate costs uses this methodology and is shown in Exhibit D1, Tab 5, Schedule 1.

Exhibit C1, Tab 2, Schedule 1 provides evidence regarding the derivation of Overhead Capitalization Rates.

### 1.4 Depreciation and Amortization Expense

The depreciation expense for Remotes' submission for the 2018 revenue requirement was based on the methodology in an independent study conducted by Foster Associates for Hydro One Remote Communities in 2011 and approved by the Board in EB-2012-0137.

The company is proposing to recover $4,608K in depreciation and amortization expenses. Remotes' evidence on depreciation expense is filed at Exhibit D1, Tab 6, Schedule 1.

### 1.5 Income Taxes

Evidence outlining the calculation of Payments of Utility Income Taxes of ($69)K appears at Exhibit D2, Tab 8, Schedule 1.

## 2.0 SUMMARY OF OM&A EXPENDITURES

The requested OM&A expenditures result from a business planning and work prioritization process that reflects risk-based decision making to ensure that appropriate, environmentally responsible and cost effective solutions are in place. This process is described in detail at Exhibit A, Tab 7, Schedule 3.

The proposed OM&A programs are required to meet public and employee safety objectives, to comply with regulatory requirements and government direction, to protect the environment, to maintain service quality and reliability at targeted performance levels, and to ensure public confidence as stewards of the assets entrusted to us.

Remotes' OM&A budget is grouped by investment categories: Generation, Distribution, Customer Care, Community Relations, Administration and Other OM&A and External Costs. Table 1 provides a summary of Remotes' OM&A expenditures for the historical, bridge and test years.

**Table 2**

**Summary of OM&A Budget (in $K)**

| Description | Board Approved | Historic (Actual) | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | **2013** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **Generation** | 36,632 | 38,522 | 40,061 | 36,197 | 37,662 | 42,696 | 44,159 |
| **Distribution** | 2,980 | 1,461 | 1,879 | 2,415 | 1,992 | 2,119 | 2,203 |
| Customer Care | 1,903 | 3,064 | 1,731 | 628 | 1,876 | 1,892 | 1,999 |
| Community Relations | 750 | 520 | 554 | 291 | 138 | 379 | 305 |
| Shared Services and Other Administrative Costs | 1,157 | 1,439 | 1,542 | 1,317 | 1,487 | 1,164 | 1,342 |
| **External Costs** | 61 | 206 | 172 | 265 | 342 | 135 | 135 |
| **TOTAL** | **43,483** | **45,212** | **45,939** | **41,113** | **43,497** | **48,385** | **50,143** |
| *% Change (year-over-year)* | - | *9.8%* | *1.6%* | *-10.5%* | *5.8%* | *11.2%* | *3.6%* |
| *$ Change (Test vs. 2013 Board Approved)* | - | - | - | - | - | - | *6,660* |
| *% Change (Test vs. 2013 Board Approved)* | - | - | - | - | - | - | *15.3%* |

Total OM&A expenditures are expected to increase by 4% or $1,758K over the 2017 to 2018 period. The increase is primarily driven by the cost of diesel fuel.

The cost drivers and detailed descriptions of the work activities in each area of Remotes' OM&A expense and the reasons for the changes in costs over the 2013 to 2018 period are discussed in the schedules that make up Exhibit D1, Tab 1, Schedules 2 to 6.

## 3.0 GENERATION

The Generation OM&A budget represents costs required to maintain and operate the existing generation stations and associated facilities to meet community loads. The proposed costs are intended to ensure that the overall reliability of the generating assets is maintained and that customer commitments are achieved, and that all legislative, regulatory and safety requirements are met. Details of the expenditures under this program are provided at Exhibit D1, Tab 1, Schedule 2.

## 4.0 DISTRIBUTION

The Distribution OM&A budget represents planned maintenance, forestry and right-of-way maintenance, trouble response, data collection and system condition assessment, and meter re-verification, testing and checking. The proposed costs are intended to ensure that the overall reliability of the distribution systems is improved, that customer commitments are met, and that all legislative, regulatory, environmental and safety requirements are met. Details of the expenditures under this program are described in detail at Exhibit D1, Tab 1, Schedule 3.

## 5.0 CUSTOMER CARE

The Customer Care OM&A expenses represent the costs associated with meter reading, customer billing, collections and bad debt expenses. Details of the expenditures under this program are filed at Exhibit D1, Tab 1, Schedule 4.

## 6.0 COMMUNITY RELATIONS

The Community Relations OM&A work program includes CDM programs, outreach activities, the Customer Advisory Board ("CAB"), and community safety program. Details of the expenditures under this program are filed at Exhibit D1, Tab 1, Schedule 5.

## 7.0 SHARED SERVICES AND OTHER ADMINISTRATIVE COSTS

The Shared Services and Other Administrative costs include the common corporate functions and services to support the Remotes business, as well as the maintenance of existing infrastructure, including business systems, facilities, and information technology. The common corporate functions and services include the provision of financial, human resource, legal, information technology and strategic planning services. Other OM&A programs also include the credits for overheads capitalized. Details of the expenditures under this program are filed at Exhibit D1, Tab 1, Schedule 6.

## 8.0 EXTERNAL COSTS

Remotes performs a small amount of unregulated external work. There are three main areas of work: assistance to the Electricity Safety Authority to facilitate inspections of Remotes' distribution systems and of customer installations; maintenance of street lights and First Nation owned generating equipment in Remotes' service territory; and assessments of the Independent Power Authority generating stations (First Nation-owned and operated generating stations in remote communities Remotes does not serve). External work is described in Exhibit D1, Tab 2, Schedule 1.

# GENERATION OM&A

## 1.0 INTRODUCTION

Due to the lack of grid connection, Remotes generates electricity to meet its obligations under section 29 of the *Electricity Act, 1998*. Diesel generation is currently the prime source of electricity within the communities. Remote also owns and operates two run-of-the-river mini-hydro electric generating facilities and has four demonstration project windmills. The feasibility of using further renewable technologies is continually examined as new technologies evolve, but diesel is currently the most reliable and cost effective technology.

There are presently 57 diesel generators in service, ranging in size from 60kW to 1500kW. Most stations have three generators, sized to meet community load at different times of the day. Automated operation ensures that the generation units are run to maximize fuel efficiency by matching the generator size to the community load. Depending on electrical demand, Remotes handles approximately 18 million litres of fuel each year.

Remotes has fuel storage tanks ("tank farms") within each community to ensure adequate diesel fuel supply. Tanks are equipped with measurement and alarm devices to reduce the risk of fuel spills and to enhance fuel control measurement. Most tanks are double-walled to enhance containment.

Due to the high cost of transportation to the communities, Remotes' staff generally reside in the communities while undertaking planned and unplanned maintenance. Remotes maintains staff houses and trailers at fourteen sites. Commercial accommodations are used at the other sites.

The proposed Generation OM&A expenditures for 2018 are $44,159K and include $27,600K for diesel fuel required to generate electricity. These expenditures are required to meet customer, regulatory and statutory requirements regarding service and reliability.

## 2.0 OVERVIEW

The Operation and Maintenance spending for historic, bridge and test years are presented in the table below.

**Table 1**

**Generation Operation & Maintenance OM&A (in $K)**

| Category | Board Approved | Historic (Actual) | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Generation Maintenance** | 6,012 | 8,648 | 9,932 | 8,610 | 9,574 | 11,392 | 11,640 |
| **Generation Operations** | 4,573 | 4,306 | 4,260 | 4,337 | 4,358 | 4,819 | 4,919 |
| **Fuel** | 24,067 | 25,568 | 25,869 | 23,250 | 23,669 | 26,485 | 27,600 |
| **Other Power Supply Expenses** | 1,980 | 0 | 0 | 0 | 61 | 0 | 0 |
| **Total** | **36,632** | **38,522** | **40,061** | **36,197** | **37,662** | **42,696** | **44,159** |

## 3.0 GENERATION MAINTENANCE

Generation maintenance includes planned and unplanned maintenance related to the generation site, buildings, engines, systems and fuel storage and fuel systems. Planned maintenance prevents premature equipment and system failures and contributes to service reliability. Unplanned maintenance includes maintenance and repair related to trouble reports and equipment or component failures.

As outlined in Exhibit A, Tab 3, Schedule 2 and in the DSP, in response to overall funding constraints, Indigenous and Northern Affairs Canada ("INAC") and Remotes have developed a more incremental approach to funding required upgrades. INAC now funds the cost of replacing an existing engine with a larger engine. In some cases, where engine rooms are too small for the new engine, INAC will also fund the cost to modify the generating station. Adopting this strategy is critical from a customer perspective. Since 2013, eight communities have been in load restrictions, where new services could not be connected to the electrical systems. The shift to more incremental funding has satisfied customer needs and expectations for safe, reliable power and has to date removed connection restrictions in seven communities. A project to remove restrictions is planned in the remaining growth-constrained community. Because the stations are not replaced by INAC as originally planned, investments are still required to maintain aging auxiliary systems and station buildings.

### 3.1 Maintenance of Diesel Engines

Planned maintenance of diesel engines is prescribed by the engine manufacturer and is required to keep generating units available and operating to meet community load. Intensive maintenance procedures are scheduled based on engine operating hours and vary from year to year. Forecasts of planned maintenance engines are based on forecast engine operating hours, not the age of the unit. Actual engine maintenance performed varies according to actual load in the community and the hours each engine is picked to run by the automated control system. Regular maintenance is also performed on the run-of-the-river hydro stations.

### 3.2 Maintenance of Plant and Auxiliary Systems

Planned maintenance of plant and auxiliary systems includes inspection and maintenance of: all electrical system and SCADA systems; secondary heating systems; engine fuel controls, primary cooling and ventilation systems; overhead cranes; and mandatory annual inspection and maintenance of fire suppression systems.

The plant auxiliary systems were installed when stations were newly constructed, and must be maintained, tested, inspected and calibrated to keep them in service. As proposed and approved in EB-2012-0137, an ongoing program to meet regulatory requirements for annual certification of fire systems was established in 2013.

### 3.3 Maintenance of Buildings

Planned maintenance related to structures includes civil repair work (required to maintain all generating station buildings, fences, yard sites and staff houses), annual inspections, and bi-annual sampling of water facilities for the staff houses and generation stations. Delays to station upgrades mean that ongoing civil repair work increases significantly as buildings that were expected to be replaced continue to age and require increased maintenance.

### 3.4 Maintenance of Tank Farms

Planned maintenance of tank farms includes expenditures required to inspect, maintain and address deficiencies in the generating station fuel offload, bulk storage tanks and fuel transfer equipment in order to keep fuel systems in standard operating condition. Fuel system maintenance is directly related to Remotes' responsibility for station operation as prescribed in the Electrification Agreements, Canadian Standards Association fuel regulations B-139-15, and Fuel Oil Regulation 212. Liquid Fuels Handling Code, Technical Standards and Safety Association.

### 3.5 Design, Construction and Asset Management (Engineering) Support

Design, Construction and Asset Management maintenance programs and projects are related to improvements in the efficiency, safety and operation of generation assets and include engineering investigations, electrical drawing projects and renewable energy improvements.

**Table 2**

**Generation Maintenance OM&A (in $K)**

| Category | Board Approved | Historic (Actual) | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Generation Maintenance** | 6,012 | 8,648 | 9,932 | 8,610 | 9,574 | 11,392 | 11,640 |

Increases in generation maintenance between the 2013 OEB-approved amounts and 2013 actual amounts are primarily due to higher unplanned maintenance, including unit failures in Weagamow, Deer Lake, Wapekeka and Fort Severn, higher maintenance of auxiliary and plant systems and renewable energy maintenance. Increased building maintenance, electrical station drawing projects and engineering investigations also contributed to this variance, partially offset by lower planned maintenance of engines.

Increases in generation maintenance between 2013 and 2014 are primarily related to higher planned maintenance of engines and increased maintenance of auxiliary and plant systems, which were identified as a leading cause of unplanned generation outages. Increased work on leak detection sensor improvements, engineering investigations, and electrical station drawing projects also contributed to the variance and are partially offset by lower unplanned engine maintenance in 2014 and lower planned and renewable energy maintenance.

Decreases in generation maintenance between 2014 and 2015 are mainly due to a shift in resources to focus on fully recoverable capital upgrade work, lower planned maintenance of engines and lower maintenance of auxiliary and plant systems which was a major focus in 2014. Lower expenditures on unplanned maintenance of engines, leak detection sensor improvements, engineering investigations, and electrical station drawing projects also contributed to this variance. These decreases are offset by higher renewable energy maintenance and increased environmental improvements.

Increases in generation maintenance between 2015 and 2016 are related to higher planned maintenance of engines, unplanned maintenance of engines, and spill detection operational improvements. Increased planned maintenance of buildings, renewable energy maintenance, and engineering investigations also contributed to this variance. These increases are offset by decreased plant maintenance auxiliaries and systems and fewer electrical station drawing projects.

Increases in generation maintenance between 2016 and 2017 bridge year forecast are associated with higher planned maintenance of engines, unplanned maintenance of engines, maintenance of auxiliary and plant systems and safety improvements, engineering investigations, and station electrical drawing projects. These increases are offset by lower planned maintenance of buildings.

Increases in generation maintenance between 2017 bridge year forecast and 2018 test year are associated with higher maintenance of engines, auxiliary and plant systems, and renewable energy maintenance.

## 4.0 GENERATION OPERATIONS

Generation operations represent expenditures required for safe and reliable day-to-day operation of the generating plants, and are required to keep the generating station and associated facilities in a standard operating condition as required to meet community load. This is associated with Remotes' responsibilities prescribed by the Electrification Agreements, the Certificate of Approval to Operate the Generating Station under the *Environmental Protection Act*, and Section 6.2.27 of the Distribution System Code.

The inaccessibility of its service territory is Remotes' greatest operational risk. Within each community, Remotes contracts for local operators, who perform regular routine inspection and maintenance of equipment at generating facilities including the generating units, auxiliary equipment and the bulk storage tank farm. The operators provide on-site monitoring of fuel deliveries, and the safe handling, transportation and disposal of waste. Operators are also responsible for keeping the stations clean, undertaking filter changes, checking diesel plants and reporting and troubleshooting problems to the Thunder Bay Service Centre. Operators are also responsible for responding to emergencies such as power outages, house fires and spills.

Operations staff in Thunder Bay is responsible for ensuring that the diesel plants operate safely and reliably. Operations staff is also the primary contact for the operators, responsible for supervising and scheduling, developing plant-specific procedures, logistical and troubleshooting support, assisting the operator in emergency response, plant reporting and for ensuring that the operators are competent to perform daily maintenance activities. Operations staff is responsible for conducting and documenting operator training. Each operator must successfully complete a comprehensive on-site training program each year. On average, each operator requires annual refresher training of two weeks to learn to operate the plant systems, respond to emergencies and perform day-to-day maintenance.

Generation operations also include a variety of environmental programs. These programs are conducted to ensure that Remotes complies with all legal and corporate requirements related to environmental protection, including obtaining and respecting Certificates of Approvals and permits for the transportation of dangerous goods and with various reporting requirements under the *Environmental Protection Act.*

In 1999, Remotes developed an Environmental Management System ("EMS") to help improve environmental performance. The EMS is registered to the ISO 14001-2015 standard and requires regular audits, spills prevention, support and training for staff and agents, and internal and public communications.

Generation operations, excluding fuel and power purchases, in the historic, bridge and test years are presented in Table 3 below.

**Table 3**
**Generation Operations OM&A (in $K)**

| Category | Board Approved | Historic (Actual) | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Generation Operations** | 4,573 | 4,306 | 4,260 | 4,337 | 4,358 | 4,819 | 4,919 |

Decreases in generation operations between the 2013 OEB-approved amounts and 2013 actual amounts are due to investments in operator training in 2012 and earlier years that led to lower compliance related items and corrective actions, improvements in on-site tools and equipment, and the successful re-negotiation of the winter road contract.

2016 expenditures were lower than planned due to an unanticipated vacancy associated with the long-term illness of one of the two operations officers. Increases in generation operations between 2016 and 2017 relate to renegotiated operator contracts and the re-establishment of two regular operations staff.

## 5.0 FORECAST OF FUEL USAGE, PRICING AND DELIVERY

Fuel purchases for the historic, bridge and test years are shown in Table 4 below.

**Table 4**

**Fuel Purchases (in $K)**

| Category | Board Approved | Historic (Actual) | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Fuel** | 24,067 | 25,568 | 25,869 | 23,250 | 23,669 | 26,485 | 27,600 |

Increases in fuel between the 2013 OEB-approved amounts and 2013 actual amounts are due to increased fuel volumes associated with higher community load, offset by a decrease in unit price. Decreases in fuel between 2014 and 2015 relate primarily to lower unit price. Increases between 2016 and the bridge year 2017 relate primarily to higher unit price. Increases between 2017 bridge year forecast and 2018 test year are due to increased volume and unit price.

Remotes forecasts load in order to plan for and meet customer loads, to estimate customer revenues and to forecast its fuel and maintenance costs. As a result of Remotes' break-even business model, cost and revenue differences between forecast loads and forecast fuel costs do not result in a profit or loss to Remotes, but are added to or drawn from the RRRP Variance Account. The load forecast methodology and statistics related to load forecast are discussed in more detail in Exhibit G1, Tab 1, Schedule 1, and in the supporting schedules to that Exhibit.

### 5.1 Fuel Usage Forecast

Remotes tracks actual historical data on energy usage by community, customer class, and time period. This historical data provides the baseline starting point for forecasting usage/kWh sold. Adjustments are made to this baseline data on a going-forward basis using average load growth, historical customer growth patterns and seasonality. Feedback is solicited from communities about upcoming construction or community programs that may impact future loads.

The Usage Forecast (kWhs sold) forms the basis of the fuel forecast. Once the usage forecast is established, historic operating fuel efficiency ratios and load loss rates are utilized to forecast generated kWhs and fuel litres required. The fuel forecast is done on a site by site basis, given different load characteristics and plant efficiencies.

Expected fuel commodity prices are based on market prices at the time the forecast is made. Fuel commodity prices are escalated based on Consumer Price Index (“CPI”). As there is no Canadian forecast for diesel fuel commodity prices, commodity pricing is confirmed through a high level analysis of the published fuel indices that are used by each supplier.

The cost of delivery accounts for about 44% of the delivered price of fuel. As a result, supply delivery contract data is critical in developing the forecast costs. Supplier contracts are subject to a competitive tendering process and delivery costs are forecast on the basis of supplier contracts and historical deliveries of winter road fuel. Air delivery typically constitutes about 56% of fuel delivered to Remotes’ communities, followed by all-weather road delivery at 13%, winter road delivery at 18% and First Nation contracts at about 13%.

**Table 5**

**Total Cost of Fuel**

| | |
|---|---:|
| Fuel Efficiency (kWh/litre) | 3.42 |
| Total litres of fuel issued (in KL) | 18,203 |
| Average delivered cost per litre ($) | $1.516 |
| Total Cost of Fuel (in $K) | $27,600 |

## 5.2 Fuel Cost Management

Overall fuel costs are affected by three main factors: price, volume and delivery. Two of these factors can be influenced by Remotes, volume and costs of delivery. Remotes has several initiatives underway to address volume. To influence fuel volumes, Remotes makes CDM available to customers, is reinvesting in its Programmable Logic Controller ("PLC") system and is installing new, more fuel efficient engines when engines are at end of life.

Since 2007, Remotes has been reducing delivery costs, by improving delivery contracts for both air and winter road fuel by improving supplier contracts, requiring that fuel levels are drawn down in advance of winter road openings and by continuing to expand its contracting with First Nation-owned tank farms for the supply and storage of winter road fuel. Fuel commodity prices, on the other hand, are the result of market forces and are not within Remotes' control.

In order to reduce diesel fuel usage, Remotes has done the following:

- Introduced a CDM program and supported the development of community-led, energy planning discussed in Exhibit D1 Tab 1, Schedule 5;
- Operated and introduced customer-owned Renewable Energy Technologies ("REINDEER program") generation facilities (Exhibit A, Tab 3, Schedule 3);
- Invested in improving fuel generating efficiency through a proactive scheduled maintenance program; and
- Maintained an active generation asset replacement program, and introduced more efficient technology.

In order to mitigate the impact of rising fuel rates Remotes has done the following:

- Negotiated long-term fuel delivery contracts with multiple suppliers;
- Maximized winter road deliveries (cheaper delivery methods) where possible through supplier relationships and improved tank storage; and
- Negotiated an increased number of fuel contracts directly with the First Nation communities with fuel storage on site where Remotes does not have adequate fuel storage facilities to take advantage of winter road delivery pricing.

## 6.0 POWER PURCHASES

### 6.1 Shoulderblade Falls Hydroelectric Station

During the 1990s, Ontario Hydro, Deer Lake First Nation and INAC jointly funded the construction of a small hydroelectric station at Shoulderblade Falls as a demonstration of renewable technology in the north. In 1999, Deer Lake and Ontario Hydro agreed that Ontario Hydro would operate the station for ten (10) years and then would transfer ownership to Deer Lake at the end of 2009. Ontario Hydro agreed to pay Deer Lake for purchased power based on the avoided cost of diesel fuel. Remotes inherited this agreement from Ontario Hydro. At the request of Deer Lake First Nation, the transfer of the station was deferred until the end of 2012. At the time of the last filing, Remotes expected to transfer the station to Deer Lake First Nation and to purchase power from the community starting in 2013. The First Nation decided to defer taking over the station for another ten (10) years; therefore, power has not been purchased from the station. In the interim, Remotes pays Deer Lake First Nation $120K per year for the use of the facility and $10K for road maintenance as part of an agreement to share the benefits of the station with the community. The benefit-sharing costs are currently included in generation maintenance. Renewable energy purchased through the REINDEER program is an offset to fuel expense. The REINDEER program is discussed further in Exhibit A, Tab 3, Schedule 3.

**Table 6**

**Shoulderblade Falls Power Purchases**

| | **2013 OEB-Approved** | **2013 Actual** |
|---|---|---|
| Total MWh purchased | 1,881 | 0 |
| Estimated Cost of Power (in $K) | $612 | $0 |

## 6.2 Forecast Power Purchases for Grid Connected Communities

Remotes expected to begin serving the communities of Cat Lake and Pikangikum in 2013. Neither community has yet signed an agreement for service with Remotes. Discussions on a service agreement with Cat Lake are currently in abeyance, as the community has requested some time to resolve certain issues with Hydro One Networks. Although discussions on the transfer of service are not currently active, Remotes staff is working with Cat Lake First Nation on a community soil remediation project (some contamination in the community relates related to the old Ontario Hydro generation station), and believes that an agreement for service will eventually be reached.

Pikangikum was unable in 2013 to get the capital required to build a distribution line to the community. In March, 2016, Pikangikum First Nation wrote to Remotes noting that it was working with the Watay project and wished to revive negotiations for a service agreement. Discussions with Pikangikum are currently active and Watay has developed a project plan to connect the community. It is Remotes' expectation that Pikangikum will receive funding for this project and that Remotes will serve the community. However, no revenues or costs associated with service to either Cat Lake or Pikangikum are included in this filing as neither community is currently expected to enter Remotes service territory in 2018.

**Table 7**

**Forecast Purchases by Community (MWhs)**

| **Category** | **Board Approved** | **Historic (Actual)** | | | | **Bridge** | **Test** |
|---|---|---|---|---|---|---|---|
| | **2013** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Cat Lake | 1,921 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pikangikum | 10,682 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total (includes line losses) | 12,603 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Cost of Power (in $K) | $1,980 | $0 | $0 | $0 | $0 | $0 | $0 |

# DISTRIBUTION OM&A

## 1.0 INTRODUCTION

Remotes served approximately 3,550 customers at the end of 2016 through nineteen isolated distribution systems to serve twenty-one communities. Within each system, Remotes is responsible for transformation, voltage regulation, delivery and metering of power. The distribution systems are isolated, distinct and stand-alone, the result of the distance between each community. These distribution systems operate at distribution voltages ranging from 4.8 kV to 25 kV. The distribution in-service assets maintained by Remotes include approximately 242 kilometers of line and transformers distributed throughout the system, which are used for voltage transformation.

The proposed OM&A expenditures are driven by the need to meet customer, regulatory and statutory requirements regarding service and reliability.

**Table 1**
**Distribution OM&A (in $K)**

| **Category** | **Board Approved** | **Historic (Actuals)** | | | | **Bridge** | **Test** |
|---|---|---|---|---|---|---|---|
| | **2013** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **Distribution Maintenance** | 2,679 | 1,399 | 1,799 | 2,216 | 1,780 | 2,008 | 2,087 |
| **Distribution Operations** | 301 | 62 | 80 | 199 | 212 | 111 | 116 |
| **Total** | **2,980** | **1,461** | **1,879** | **2,415** | **1,992** | **2,119** | **2,203** |

Distribution maintenance includes both planned and unplanned maintenance and trouble calls. Unplanned power interruptions on the distribution system generally result from line component failures and contact by trees or animals. Unplanned maintenance is reactive and varies due to external factors such as storms, variability in equipment deterioration and random equipment failures. Planned maintenance includes equipment maintenance that is primarily cyclical in nature, including maintenance of line equipment (reclosers and line regulators).

Distribution maintenance also includes costs associated with metering. Revenue metering is federally regulated under the *Electricity and Gas Inspection Act* and is governed by Measurement Canada. Under Measurement Canada regulations, all revenue meters must be approved and routinely inspected and maintained. Remotes complies with Measurement Canada rules and regulations. Based on Measurement Canada rules, meters must regularly be removed from service to verify that they are performing accurately and within specifications. Electricity customers require a meter to measure their electricity usage, and the proper functioning of billing meters is essential to ensure customers are neither overbilled nor underbilled.

Distribution operations includes data collection and system condition assessment used to plan corrective and preventative maintenance, joint use activities and engineering support for distribution. The Distribution System Code requires that all local distribution companies assess the condition of its assets and patrol their distribution lines to identify structural problems, damaged equipment and components that may cause a power interruption, as well as any hazards such as leaning poles, damaged equipment enclosures and vandalism.

Distribution maintenance in 2013 was lower than the OEB-approved 2013 level primarily due to the delay in reaching service agreements with Cat Lake and Pikangikum. The cancellation of collection trips due to the implementation of the CIS project also contributed to the lower than planned spending.

Higher distribution maintenance expenditures in 2014 compared to 2013, primarily reflect the resumption of collection trips after CIS stabilization and increased planned forestry activities, partially offset by lower trouble calls.

Higher distribution maintenance expenditures in 2015 compared to 2014 primarily reflect increased trouble response, planned maintenance, and forestry activities.  Increased distribution operations expenditures in 2015 compared to 2014 reflect increased costs related to a project to automate distribution data collection.

Lower distribution maintenance in 2016 compared to 2015 primarily reflects a decrease in planned forestry activities.

Higher distribution maintenance in 2017 compared to 2016 primarily reflects an increase in planned forestry activities.  Remotes is currently on track to complete the planned distribution maintenance in 2017.

# CUSTOMER CARE OM&A

## 1.0 INTRODUCTION

Remotes provides general customer account services including in-community customer service activities to all customers connected to its distribution system. These services are established by Remotes' Distribution Licence, rate schedules, and in the Codes and Rules established by the Board, and are documented in Remotes' Conditions of Service. Remotes' customer care team is responsible for billing, collections, meter reading, and responding to customer inquiries and complaints.

The Customer Care spending for historic, bridge and test years is shown in Table 1 below. Bad Debt expense is included in the Customer Care OM&A category.

**Table 1**
**Customer Care OM&A (in $K)**

| **Category** | **Board Approved** | **Historic (Actuals)** | | | | **Bridge** | **Test** |
|---|---|---|---|---|---|---|---|
| | **2013** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Customer Care | 1,855 | 2,844 | 1,906 | 1,733 | 1,897 | 1,857 | 1,939 |
| Bad Debt | 48 | 220 | (175) | (1,105) | (21) | 35 | 60 |
| **Total** | **1,903** | **3,064** | **1,731** | **628** | **1,876** | **1,892** | **1,999** |

## 2.0 CUSTOMER CARE

Customer care expenses include costs to read meters, bill customers, collect on outstanding accounts and respond to customer inquiries. Remotes has two staff in the Thunder Bay service centre who are responsible for entering meter readings into the Customer Service System, answering customer calls and inquiries, entering bill payments, organizing collection trips, contacting customers and Band Councils prior to collection activity and negotiating payment arrangements. Field staff undertake collection activities in the communities. Meter reading is contracted out through Band Councils to individuals in the communities.

Higher customer care spending in 2013 compared to the Board-approved 2013 level, is due to Remotes' involvement in the project design and implementation of the CIS billing system. Lower customer care spending in 2014 compared to 2013 reflects the implementation of the CIS billing system in 2013 as required involvement in the project wound down.

## 3.0 BAD DEBIT

Bad debt expense is made up of direct write-offs offset by recoveries, plus adjustments to the provision for bad debts. The bad debt allowance is based on a combination of applying a model percentage against outstanding energy accounts receivables and specific identification of high risk receivables. The provision is an allowance taken against receivables where full recovery is in doubt and is determined using allowance rates on previous actual payment history, the normal payment curve and specific adjustments for large or unusual receivables based on management judgment. Adjustments to this allowance are charged to bad debt expense when outstanding receivables increase. When outstanding balances are reduced, the provision is reduced and the adjustments are credited to bad debts.

Credits to bad debt expense in 2014 and 2016 reflect Remotes' success in negotiating payment arrangements with First Nation Band Councils. The credit in 2015 primarily reflects the successful early completion of a long term payment plan. Since January 2013, outstanding First Nation accounts receivable have been reduced from $4,407K to $2,613K in December 2016, when most First Nations had successfully completed their payment plans. As a result of these successful payment arrangements, the provision has been reduced. Bad debt expense is expected to increase to reflect the conclusion of most of these payment plans in the bridge and test years.

# COMMUNITY RELATIONS OM&A

Community Relations expenses include various customer outreach activities, including a Conservation and Demand Management (CDM) program, the Customer Advisory Board (CAB) and public safety measures such as the joint use program.

**Table 1**

**Community Relations ($K)**

| Category | Board Approved | Historic (Actuals) | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Total** | **750** | **520** | **554** | **291** | **138** | **379** | **305** |

Until 2016, CDM was the largest element of Remotes' Community Relations activities. Between 2011 and 2014 CDM activities were carried out by the Remotes' Conservation and Renewable Energy ("CaRE") officer. Most of Remotes' customers are residential, therefore the program focused on residential conservation. In 2013, Remotes' customers also benefited from an Ontario Power Authority ("OPA") Program that also focused on residential customer conservation. Between the two programs, most customers participated in programs that were designed to develop sustainable conservation by developing local expertise and buy-in, and from access to energy efficient products and appliances.

In 2013 and 2014, the OPA and the federal government also sponsored the development of community energy plans in various communities that Remotes serves. Remotes supported this work by offering advice and information on usage and costs. These energy plans included conservation, but also focused on renewable energy development, alternatives to diesel fuel and the potential for grid access. By 2015, most Band Councils expressed a preference for Remotes to focus on activities related to grid-readiness and on opportunities for renewable energy development. Where conservation was seen as a priority, it was directed toward Band accounts (i.e., Standard A customers) as these rates are much higher and were making it difficult for Band Councils to pay their bills. Remotes therefore decided to continue to offer residential programs through an application based program, and to also offer its commercial customers separate application-based programs. The move to application-based programs resulted in lower program spending part way through 2015 and 2016 and is also reflected in the bridge and test years.

Other Community Relations activities include Remotes' Customer Advisory Board ("CAB"), customer research activities, customer communications and community relations expenses such as community meetings. Remotes surveys its customers and Band Councils annually to discuss service satisfaction, planned program activities, areas that services can be improved and related matters. Customer communications includes bill inserts and other mailings to customers. Community relations activities include community meetings and other outreach activities to discuss service issues. CAB members are residential and commercial customers from within Remotes' service territory. The CAB offers advice on service policies and procedures, and ways to improve services within the communities. Costs for this program are related primarily to meeting facilities, transportation to meetings and travel expenses for CAB members. See Exhibit A, Tab 4, Schedule 1 - Customer Service and Engagement Strategy for information on CAB discussions.

Variances from 2014 to 2016 relate to reduced spending on CDM activities. The CDM expenditure level is expected to return to the normal level in 2017. Variances from 2017 to 2018 relate to an expected increase in uptake of conservation programs and a small increase in community outreach activities related to public safety and community meetings.

# SHARED SERVICES AND OTHER ADMINISTRATIVE COSTS

## 1.0 SHARED SERVICES

The shared service model allows for the delivery of specialized services performed by Hydro One without replicating these functions within each separate subsidiary. Shared Services include common corporate functions and services ("CCF&S"), telecommunications, enterprise technology, supply management services and the use of assets.

Benefits to Remotes include the following:

- Ensures availability of required specialised professional expertise and resources in diverse areas;
- Ensures application of consistent policies, governance frameworks, business processes;
- Rationalizes and offers consistent levels of service across all Hydro One subsidiaries irrespective of size (human resources, pay and financial services, infrastructure support);
- Uses common technology systems and platforms providing better access to high quality and accurate information and to required services; and
- Allows Remotes to benefit from economies of scale in such areas as accounts payable processing, procurement processes and management of supplier relationships.

**Table 1**

**Remotes' Shared Services (in $K)**

| Description | Historic | | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 OEB Approved | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **CCF&S** | 905 | 868 | 993 | 956 | 1,144 | 1,032 | 1,027 |
| **Enterprise Technology Services** | 217 | 213 | 219 | 266 | 219 | 145 | 135 |
| **Telecommunications Services** | 118 | 124 | 125 | 140 | 135 | 141 | 140 |
| **System Services & Lease of Computer Equipment** | 180 | 219 | 299 | 299 | 276 | 261 | 261 |
| **Customer System Operations** | 53 | 54 | 39 | 43 | 43 | 46 | 47 |
| **Total Shared Services** | **1,473** | **1,478** | **1,675** | **1,704** | **1,817** | **1,625** | **1,610** |
| **Supply Chain Services** | 77 | 76 | 76 | 76 | 76 | 76 | 76 |
| **Total** | **1,550** | **1,554** | **1,751** | **1,780** | **1,893** | **1,701** | **1,686** |

CCF&S are also discussed in Exhibit A, Tab 6, Schedule 1, and include Corporate Management, Finance, Outsourcing Services, Internal Audit, Tax, Legal, Corporate Secretariat, Regulatory, Corporate Communications and Services, First Nation and Metis Relations, Security, Human Resources and Labour Relations.

## 2.0 OTHER ADMINISTRATIVE COSTS

Other Administrative Costs include Remotes' project costs, Ontario Energy Board cost assessment, costs awards and proceeding-specific costs and expenses related to the

OEB's Low-Income Emergency Assistance Program. No political or charitable donations have been made or are planned for recovery.

**Table 2**

**Other Administrative Costs (in $K)**

| Description | Historic | | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | OEB Approved | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **OEB Initiated Regulatory Expenses** | 86 | 122 | 129 | 142 | 68 | 40 | 50 |
| **Applicant Driven Regulatory Expenses** | 54 | 140 | 9 | 0 | 0 | 90 | 125 |
| **Low-Income Energy Assistance Program (LEAP)** | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| **Total** | **192** | **314** | **190** | **194** | **120** | **182** | **227** |

Regulatory expenses include the Ontario Energy Board's allocation of its expenses to Remotes and Section 30 costs associated with OEB led proceedings. Year over year variances in 2013, 2014 and 2015 relate primarily to differences in OEB initiated Section 30 costs. Variances between 2015 and subsequent years relate to the new cost allocation methodology adopted by the Board. Variances between 2013 OEB-approved and 2013 actual amounts reflect intervenor costs for EB-2011-0021 and EB-2012-0137. Increased expenses in 2017 reflect the cost for Notice and for consultant support for the DSP. Test year expenses primarily reflect expected intervenor cost awards. Details related to these costs are shown in Exhibit D2, Tab 6, Schedule 1.

LEAP is an OEB directed initiative, which started in 2011.

## 3.0 TOTAL SHARED SERVICES AND OTHER ADMINISTRATION

Total Shared Services and Other Administration include credits associated with direct program assignments, non-energy bad debts and capitalized overheads.

Direct Program Assignments are services that can be directly assigned to an OM&A program, such as billing. These are deducted from Shared Services and Administration. Non-energy bad debts are also removed and are included in Customer Care (Exhibit E1 Tab 1, Schedule 4).

Capitalized Overheads are the portion of Common Corporate Costs attributable to overhead and indirect costs related to capital projects that are capitalized, as discussed in Exhibit C1, Tab 2, Schedule 1 and are deducted from Shared Services and Other Costs.

**Table 3**

**Total Shared Services and Other Administrative Costs (in $K)**

| Description | Historic | | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 OEB Approved | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Shared Services** | 1,550 | 1,554 | 1,751 | 1,780 | 1,893 | 1,701 | 1,686 |
| **Other Administrative Costs** | 192 | 314 | 190 | 194 | 120 | 182 | 227 |
| **Total** | **1,742** | **1,868** | **1,941** | **1,974** | **2,013** | **1,883** | **1,915** |
| **Less Direct Program Assignments** | (130) | (130) | (115) | (119) | (119) | (122) | (123) |
| **Less Capitalized Overheads** | (455) | (320) | (342) | (556) | (410) | (562) | (448) |
| **Total Shared Services and Other Administration** | **1,157** | **1,418** | **1,484** | **1,299** | **1,484** | **1,199** | **1,342** |

# COST OF EXTERNAL WORK

## 1.0 OVERVIEW

Remotes performs a small amount of external work for other parties. The main areas of work are: 1) assistance to the Electricity Safety Authority and other parties to facilitate their work in the communities; 2) maintenance activities (streetlights and First Nation-owned generating equipment in Remotes' service territory) and engineering design and assessments related to the connection and integration of renewable generation to Remotes' electricity distribution and generating systems; and 3) assessments of the Independent Power Authority ("IPA") generating stations (First Nation owned and-operated generating stations in remote communities that Remotes does not serve).

Assessments of IPA assets are undertaken from time to time in cooperation with Watay/OSLP ("Opiikapawin Services Limited Partnership"), Indigenous and Northern Affairs Canada ("INAC") and the local community. Assessments identify operational risks and efficiency measures that could be undertaken by INAC or the local First Nation. Connection impact assessments for renewable energy facilities wishing to connect to Remotes' distribution systems may also include engineering design work associated with integration with the existing diesel plant, depending on the size of the installation.

Costs related to external work are shown in Table 1. Revenues from external work are an offset to the revenue requirement and are discussed in Exhibit G1, Tab 3, Schedule 1.

**Table 1**

**Costs Related to External, Unregulated Work (in $K)**

| Category | Board Approved | Historic (Actuals) | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Total** | **61** | **206** | **172** | **265** | **342** | **135** | **135** |

The increase in external costs from 2013 OEB-approved to 2013 actuals is due to connection and commissioning of the temporary trailer in the community of Weagamow. Higher external costs in 2015 as compared to 2014 are due to higher ESA requests and the completion of a tank farm in the community of Sachigo. Higher external work in 2016 compared to 2015 due to the completion of a street light retrofit in the community of Weagamow and engineering design work associated with customer-owned renewable energy facilities. Lower external costs in 2017 and 2018 result primarily from fewer projected customer impact/system assessments related to renewable energy and fewer expected IPA community assessments.

# CORPORATE STAFFING

## 1.0 STAFFING STRATEGY AND OVERVIEW

Remotes' work is performed by regular staff, hiring hall staff, co-op students and summer students, services purchased from Hydro One Networks Inc., contracts with external firms who provide environmental services and by contracts for services with local communities, for agents and meter readers, and for casual resources related to land assessment and remediation, construction and CDM projects. Over 40% of Remotes' work is performed by non-regular resources.

Remotes has fifty-one full-time, regular staff. Remotes' work program has increased significantly over the past four years. Most of the increased work program has been handled through non-regular staff. Additional resources used to supplement Remotes' regular employees include casual skilled trades staff contracted through the Hiring Hall (Power Workers' Union) and temporary staff. Together with students and apprentices, Remotes employs approximately ten full-time equivalent hiring hall staff, apprentices and students each year.

Remotes staff complement performs the following functions: design and manage generation and distribution assets, construction planning, project management and commissioning, environmental management and support services, financial support and services, regulatory support and services, customer outreach, contact and billing/collection services, program management, work execution, planning and management/supervision, skilled electrical and mechanical trades work and fuel and material inventory management.

Due to the nature of Remotes' service territory, extensive travel and time away from home may be required. Staff retention and recruitment can therefore be challenging. Additionally, about 41% of Remotes employees are eligible for an undiscounted retirement over the next five years. Remotes has a number of regular staff positions that are essentially "one of" positions. If an employee leaves the company to retire or pursue other opportunities, Remotes' work program can be negatively affected until the job duties are mastered by the departing employee's replacement.

To address the training risk associated with staff retirements, Remotes creates succession plans for key employees and attempts to offer some overlap between new employees and retiring employees so that a skill and knowledge transfer can take place. Remotes also participates in Hydro One Networks Inc. established recruitment, apprenticeship and training programs, and benefits from opportunities to employ skilled staff on a temporary basis (on rotations for example). Three full-time equivalent apprentices and three full time equivalent co-op/summer students are used to supplement regular and hiring hall (casual) staff resources.

Contracts with First Nation Agents/Operators through Band offices provide the following functions: minor maintenance on diesel generators; initial emergency response and assessment; fuel delivery, receipting and inventory monitoring; diesel station and staff house janitorial work; line switching in the event of a house fire; and meter reading. External workers are also secured through Band offices for translation and logistical assistance for community/customer meetings, to work on construction projects and on Land Assessment and Remediation projects.

Remotes also contracts with Hydro One Networks Inc. for various services. These contracts give Remotes access to a greater pool of employees than would otherwise be the case for a small utility. Remotes also secures lines and trouble response services, forestry services, purchasing services, legal services, information technology services, corporate accounting services, safety and work methods and training services from Hydro One Networks Inc. under Service Level Agreements. These agreements allow Remotes to supplement their regular staff and to access professional and trades staff required on a less than full-time basis.

## 2.0 STAFFING STRUCTURE

There are seven main categories of labor resources:

(i) PWU-represented staff: The PWU is an industrial union that represents the trades, technicians and clerical workers. Within Remotes, PWU staff perform line work, electrical, mechanical, protection and control, civil, stock keeping, other technical and clerical/administrative work. These include Hydro One electrical maintainers, line maintainers, mechanical maintainers, engineering technicians and administrative employees.

(ii) Society-represented staff: The Society is a professional union that represents engineers, accounting, technical, administrative and supervisory staff. They perform engineering, high level technical and administrative work as well as supervisory functions.

(iii) Management staff are excluded from representation because they carry out managerial duties or work on confidential labour relations matters or legal matters.

(iv) Temporary Employees who are employees performing work in any of the three categories set out above and who are engaged in work that is not of a continuing nature.

(v) Contracted Staff are individuals engaged as independent contractors and are not on Remotes' payroll. They are engaged for varying amounts of time and paid varying amounts commensurate with their skill sets and the market rate for that skill.

Contract staff are tracked and charged to Remotes by work programs or activities and not by headcount. Where applicable, the procurement of contract staff is governed by the terms of the collective agreements between the Corporation and its respective unions.

(vi) Station operator agents and meter readers are community-based resources normally contracted through the local Band Council. Station operators are responsible for routine inspections of the diesel plants; minor maintenance such as changing oil filters; reporting station problems to the Thunder Bay service centre; monitoring fuel deliveries; emergency response; and the safe handling and disposal of waste. Remotes has an agent and a back-up agent for each station. Meter readers are responsible for reading meters and for reporting meter readings to the Thunder Bay Service Centre. Remotes has a meter reader in each community.

(vii) Casual workers are used for building projects, Land Assessment and Remediation projects and CDM projects. Casual workers may be acquired through the PWU hiring hall, or contracted through local Band Councils, depending on the type of work and skills available in the community.

As a subsidiary of Hydro One, Remotes is subject to the same collective agreements as Hydro One Networks Distribution and Transmission. PWU and Society-represented staff are compensated in accordance with the collective agreements negotiated by Hydro One. Remotes' Management Staff are non-Executive management and are compensated through base salaries and a short-term incentive plan that rewards performance. Detailed information on wages, salaries and overtime payments related to regular, temporary and hiring hall employees can be found in Exhibit D2, Tab 5, Schedules 1 and 2.

# PENSION AND BENEFIT COSTS (“OPEBS”)

## 1.0 PENSION COSTS

Remotes is a participant in the Hydro One Pension Plan (“the Plan”). The Plan is a contributory, defined-benefit pension plan whose members are comprised of represented employees of the Power Workers Union (“PWU”), the Society of Energy Professionals (“Society”), non-represented Management (“MCP”) employees, pensioners who were employees, and pensioners who are beneficiaries of employees or pensioners.

The Plan covers Hydro One and its subsidiaries, except Hydro One Sault St. Marie Transmission. The Plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for Remotes, the Plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded on Remotes’ financial statements.

Hydro One recovers its pension expense on a cash basis. Hydro One believes this method is more beneficial to its customers than the accrual method because it results in a lower cost recovered through rates. The cash method is also more predictable, allowing Hydro One to forecast the effect on rates for up to a three-year period.

The Board has previously accepted cash payments related to pension obligations to be included in revenue requirement (RP-1998-0001) for Hydro One and its subsidiaries, and has approved full recovery of these cash payments in various proceedings since then. The Board and intervenors accepted this treatment for Remotes’ pension obligations in EB-2012-0137.

For Remotes, the charge to be recovered through rates in 2018 is $1,707K provided in Table 1 below.

**Table 1**
**Pension Costs (in $K)**

| Category | Board Approved | Historic (Actual) | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | **2013** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **OM&A** | 799 | 1,064 | 1,198 | 1,084 | 712 | 1,149 | 1,220 |
| **Capital** | 401 | 338 | 347 | 464 | 285 | 552 | 487 |
| **Total** | **1,200** | **1,401** | **1,545** | **1,548** | **997** | **1,701** | **1,707** |

## 2.0 ACTUARIAL CALCULATION

The most recent actuarial valuation for the Plan was as at December 31, 2016. In May 2017, Hydro One filed this actuarial valuation with the Financial Services Commission of Ontario ("FSCO"). The valuation showed that the Plan had a surplus of $434 million, on a going-concern basis. Starting in 2017, the required contribution for the Hydro One companies was set at $73 million, variable based on the level of base pensionable earnings. In accordance with applicable regulations, Hydro One makes all required contributions on a monthly basis.

Hydro One's next actuarial valuation is required by December 31, 2019. The valuation will depend on investment returns, changes in benefits, and actuarial assumptions.

During 2014, 2015 and 2016, actual contributions were $174 million, $177 million, and $110 million, respectively. Actual contribution requirements in 2018 may differ depending on the level of base pension earnings used to compute the monthly contribution.

## 3.0 PENSION PLAN GOVERNANCE AND PERFORMANCE

Hydro One is the Plan sponsor and administers the pension assets and obligations of the Plan. As of December 31, 2016, the Plan had a reported net asset value of $6,870 million and about 13,087 members. Approximately 42% of the Plan's members are active. The remaining Plan members are inactive, either retired, beneficiaries of retirees, former employees eligible for a deferred pension, or members on long-term disability.

The Fund has consistently outperformed the benchmark made up of passive market indices. In the period from June 29, 2001 (the Fund's inception) to December 31, 2016, the Fund returned 7.04% annualized while the Fund's target benchmark is 6.80%, thus outperforming its target benchmark return by 0.24%. The fund's investments are divided into asset classes and each asset class has a corresponding market index (i.e. Canadian Equities market index is the S&P/TSX). The actual performance of each asset class is then measured against this market index (policy benchmark). The Fund's policy benchmark is a calculated weighted average benchmark based on the Fund's strategic asset mix.

## 4.0 DEFINED CONTRIBUTION PENSION PLAN

Effective January 1, 2016, Hydro One introduced a Defined Contribution Pension Plan ("the DC Plan"). The DC Plan allows eligible employees to contribute up to 6% of their pensionable earnings with a 100% match of contributions by Hydro One. The DC Plan is open to all new MCP employees, who are no longer eligible to participate in the Plan.

## 5.0 OTHER POST-EMPLOYMENT BENEFITS ("OPEB") COSTS

Hydro One utilizes the accrual method for accounting of OPEBs costs. The accrual method is appropriate because it reflects the costs incurred during the time period and, as such, more accurately attributes those costs to the appropriate ratepayers. Table 2 summarizes historical and forecast OPEB costs included in rates.

**Table 2**

**OPEB Costs Included in Rates (in $K)**

| **Amounts Included in Rates** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **Total** |
|---|---|---|---|---|---|---|---|
| OM&A | 775 | 941 | 760 | 866 | 846 | 909 | **5,096** |
| Capital (Note 1) | 250 | 272 | 325 | 347 | 406 | 363 | **1,963** |
| **Total** | **1,025** | **1,213** | **1,085** | **1,213** | **1,252** | **1,272** | **7,059** |
| Paid Benefits Amounts | 264 | 91 | 51 | 63 | 576 | 605 | **1,650** |
| Net Excess - amount included in rates vs. amount actually paid | 761 | 1,122 | 1,034 | 1,150 | 676 | 667 | **5,409** |

Note 1 – The Capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net Excess as noted does not represent the excess recovery in each year.

In March 2017, the Financial Accounting Standards Board ("FASB") issued an Accounting Standard's Update (ASU 2017-07) that affects the accounting for pensions and OPEBs effective January 1, 2018.

As part of ASU 2017-07, Topic 715 – Compensation – Retirement Benefits of the US GAAP Accounting Standards Codification has been amended. The amendments allow only the service cost component of the net periodic pension cost and net periodic post-retirement benefit cost to be eligible for capitalization when applicable. For rate-setting purposes, Remotes accounts for its pension costs on a cash basis and therefore this amendment is not anticipated to affect the amounts included in this application. The changes to the accounting for OPEB, which Remotes accounts for on an accrual basis for rate-setting purposes, will affect this application.

The re-classification of these elements to OM&A would have an adverse impact on rates in a given year. As Remotes operates on a break-even basis, the net periodic post-retirement benefit cost other than service cost that would have been classified as capital prior to the issuance of ASU 2017-07 will flow through the RRRP account effective January 1, 2018.

# COSTING OF WORK

## 1.0 OVERVIEW

Remotes' work program costs are comprised primarily of expenditures associated with labour, equipment, material acquisition and sundry. Consistent with common industry practice, trade labour and equipment hours are distributed directly to benefiting programs and projects by weekly time-entry. Standard hourly labour and equipment rates are then used to convert the reported hours into costs. Both labour and equipment rates are "fully loaded" to ensure that all associated support costs required to deploy resources and equipment are accurately and cost effectively distributed to the benefiting work.

In terms of material and contract costs, a material surcharge is included in this cost category to capture material and contract services procurement costs benefiting the particular program or project. In the case of distribution capital projects and external sales, a freight surcharge is also included to distribute the freight costs associated with the winter road delivery of distribution line materials into the remote communities.

As thirteen of the communities Remotes serves are not accessible by year-round road, staff, equipment and cargo are transported to the communities by aircraft. Remotes contracts out the passenger and cargo transportation services. Flight costs are charged to the project that the personnel are working on. Cost efficiencies achieved by co-ordination of work crew scheduling are captured whenever possible.

Remotes staff most often stay several days at a time in the company's staff house in the remote community in which they are working. To efficiently reflect the cost of food to direct work, food expense is allocated to all projects in which there are labour hours incurred by trade and technical staff. This cost is implicit in the labour rate ("fully loaded") and is $5 per hour in the test year.

In terms of estimating and costing capital work, there may be circumstances when removal costs or customer contributions need to be separately identified. The cost of removal work is accounted for as Depreciation and Amortization and customer contributions are netted against the gross capital costs. Capital work also receives a monthly charge for its share of Corporate Common Functions and Services, overhead costs and capitalized interest where applicable.

## 2.0 PROJECT / PROGRAM MAJOR COST CATEGORIES

### 2.1 Standard Labour Rates

On an annual basis, Remotes' standard labour rates are derived based on information gathered through the annual budgeting process. Resource budgets for each major resource category are calculated and categorized into three basic cost components; forecast billable (direct charged) hours, forecast non-billable hours and forecast non-billable expenses. Total payroll costs include allowances (as per negotiated contracts), company benefits, Government obligations and contractual time away from work (vacation, statutory holidays, sick leave) along with assigned Remote administrative costs. Those total payable costs are divided by the forecast billable hours, to create the Remotes standard labour rates. The cost elements embedded in the standard rate are illustrated in Table 1 and explained in the pages following, using the Remotes Technician rate as an example.

**Table 1**

**Remote Communities Technician (Regular Staff) 2018 Forecasted Labour Rate**

| Rate Component | Billable $ per Hr. |
|---|---|
| Meal Surcharge | $5 |
| Payroll Obligations | $70 |
| Non-Labour Administration Costs | $13 |
| Non-Project, Administration, Management and Support Services Labour | $81 |
| **Total** | **$169** |

### 2.1.1 Payroll Obligations ($70)

A brief description of the cost elements included in this category is provided below.

Labour and Payroll Allowances (75.3% of Payroll Obligations)

- Base Pay: Contractually negotiated and reflected in union wage schedules.
- Overtime: Contractually negotiated.
- Payroll Allowances: Allowances are also contractually negotiated and stated in union collective agreements. Regular staff (PWU) are entitled to travel, footwear and on-call allowances. Casual trades are entitled to travel and subsistence allowances where circumstances permit. Staff are also entitled to Northern and Remote overnight and lodging allowances when working directly in communities served by local diesel generation.

Company Benefits (20.6% of Payroll Obligations)

- Regular Staff: Comprised of Pension (12.4% of base pensionable earnings) and current and post employment benefits; health, dental, etc. (29.3% of base pensionable earnings).

Government Obligations (4.1% of Payroll Obligations)

- Consists of Canada Pension Plan, Employment Insurance, Employee Health Tax and Workplace Safety and Insurance Board Schedule 1 Premiums;
- In 2018, 5.5% is to be applied against total earnings (includes base pay, bonus, overtime, benefits and taxable allowances) to recover these costs.

### 2.1.2 Non-Labour Administration Costs ($13)

This category consists primarily of non-labour expenses incurred by the business necessary for the business operations. This includes facility costs related to the main office, property taxes, utilities, telephone, insurance, maintenance, materials and supplies. It also includes items such as travel, training, advertising, postage, office supplies and low value computer equipment and services. Non-labour administration costs are budgeted based on historical trends and consider current company initiatives and individual interdepartmental needs.

### 2.1.3 Non-Project, Administration and Support Services Labour ($81)

This category consists of labour costs incurred in non-project, administrative, management or support service roles. These costs include management and technical staff providing support services to manage and monitor the status of the assigned programs and projects. Some other functions include finance, stock-keeping, fuel management and flight logistics. Additionally, it includes time for attendance at safety meetings, housekeeping and downtime often resulting from inclement weather. This category includes employee vacation and statutory holidays, all established and identified in union collective agreements; sickness costs are also included. These estimates are based on historical trends and consider current company initiatives.

### 2.2 Transport & Work Equipment ("T&WE")

Remotes utilizes Hydro One Networks Inc. owned fleet assets as per the conditions of the Service Level Agreement ("SLA") with Hydro One Networks Inc. This SLA is for fleet management, maintenance, repair and rental services relating to the use of transport and work equipment used by Remotes. Remotes incurs the cost of transporting T&WE into the remote locations as well as flight costs associated with sending the Hydro One Networks Inc. fleet mechanic to these locations. Periodically, Remotes also incurs fuel and maintenance costs outside of those incurred by Hydro One Networks Inc. (and included in the SLA). Each equipment class has a standard equipment rate which is calculated by dividing the annual forecast cost by the annual forecast hours the class of equipment is required to work (utilization hours). Utilization hours are derived based on a review of historical trends and an annual review of the upcoming work program.

| | |
|---|---|
| 2018 TWE Cost Forecast (including SLA) | $1,153K |
| 2018 Forecasted TWE Hours | 24,386 |
| 2018 Total Average TWE Rate/Hour | $47 |

### 2.3 Material Costs and Surcharges

Material costs charged to a project or program are based on the issue cost from Inventory, which is the Average Unit Price or the direct-shipped purchase order price. On a monthly basis, the total monthly material and contract charges are surcharged with a fixed percentage to cost effectively recover the Corporate Common Functions and Services cost allocation to Remotes for services provided by Supply Management Services ("SMS"). These are costs associated with purchasing, negotiating contracts and transportation management. The percentage rate is derived by assigning the costs of SMS to projects based on an annual material and contract forecast. The 2018 forecasted SMS rate is 1.0%.

A freight surcharge is applied to all distribution capital and external work in order to allocate freight costs incurred for winter road delivery of distribution inventory line materials to remote communities. The percentage rate is derived by using the forecasted freight expense and projected material expense for planned distribution capital.

### 2.4 Sundry – Passenger Flight Costs and Meals

The cost of transporting staff to remote locations is charged to the project that is benefiting from this expense. This service is tendered to obtain the most cost competitive contract. Efficiencies are achieved with coordinating the schedule of work and work groups to share flights.

In order to carry out operating, maintenance and capital work activities, it is necessary for trade and technical staff to stay overnight in remote communities at Remotes' staff houses on an ongoing basis. Food supplies are required and the cost of these supplies is allocated to direct work programs based on labour hours charged by the two primary trade and technical labour groups and is therefore recovered in the hourly charge out rate. The rate per hour is based on forecasted meal expense and planned labour hours.

# DEPRECIATION AND AMORTIZATION EXPENSES

## 1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of Remotes' depreciation and amortization expense for the 2018 test year.

The depreciation expense for Remotes' submission for the 2018 revenue requirement was based on the methodology in an independent study conducted by Foster Associates for Hydro One Remote Communities in 2011 and approved by the Board in EB-2012-0137.

Amortization expense pertains to costs the Board has allowed Remotes to defer for recognition at a future date. The Board has, in past decisions, approved the amount of the cost to be deferred for future recovery, the prescribed period or method of amortization and prescribed the time period over which the costs in each account should be amortized. Historical, bridge and test year amortization schedules are filed at Exhibit D2, Tab 7, Schedule 1.

## 2.0 DEPRECIATION EXPENSE

The aforementioned Foster methodology was used in determining the depreciation expense for the 2018 test year. Historical, bridge and test year depreciation expense schedule is filed at Exhibit D2, Tab 7, Schedule 2.

**Table 1**

**Depreciation Expense (in $K)**

| Description | Board Approved | Historic | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | **2013** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Depreciation on Fixed Assets | 2,596 | 2,563 | 2,594 | 2,711 | 2,751 | 2,877 | 2,942 |
| Asset Removal Costs | 721 | 590 | 430 | 969 | 620 | 1,041 | 634 |
| **Total** | **3,317** | **3,153** | **3,024** | **3,680** | **3,371** | **3,918** | **3,576** |

Fixed asset removal costs are charged to depreciation expense on an "as incurred" basis. Removals increased significantly in 2015 and 2017 (projected) due to a higher level of engine replacements.

OEB Chapter 2, Appendix 2-BB – Service Life Comparison, is not applicable as Remotes does not have an expected change in asset life.

OEB Chapter 2, Appendix 2-C – Depreciation and Amortization Expense for 2013 to 2018 are filed at Exhibit D2, Tab 10, Schedules 1 to 6. The variances are due to the following:

- The OEB model calculates depreciation expense on Net Book Value (NBV) whereas Remotes uses Cost.
- The OEB model assumes a straight line depreciation rate based on the life of the asset whereas Remotes uses the rates provided by their depreciation consultants, Foster Associates, based on Iowa Curves.

OEB Chapter 2, Appendix 2-C (2013) has a material variance of $562K for USofA 1670 (Prime Movers). The 2013 NBV for 1670 is low as many assets in this category were at or approaching the end of their useful lives, resulting in a low estimate for depreciation expense for 2013 per the OEB calculation on NBV instead of Cost. The adjustments from the 2011 Depreciation Study are reflected in the 2014 opening balances. An increase in the useful life for USofA 1670 (Prime Movers) caused a decrease in the depreciation rate, resulting in lower variances for the 2014 to 2018 years.

## 3.0 AMORTIZATION EXPENSE

Remotes recognizes a liability for estimated future expenditures required to remediate past environmental contamination associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. Since these expenditures are expected to be recoverable in future rates, Remotes has recognized an equivalent amount as a regulatory asset. This balance is amortized as expenditures as they are incurred each year. The Board accepted this accounting treatment for Remotes in EB-2005-0020, EB-2008-0232 and in EB-2012-0137. The treatment of these costs in this Submission is consistent with the treatment in those proceedings. Remotes reviews its estimates of future environmental expenditures on an annual basis.

**Table 2**

**Amortization Expense (in $K)**

| Description | Board Approved | Historic | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | 2013 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| Environmental Assets | 2,713 | 1,656 | 1,599 | 1,222 | 1,247 | 1,163 | 1,032 |

Table 2 shows historic bridge and test expenditures of Land Assessment Remediation ("LAR"). The LAR program involves assessment of historically contaminated lands, the implementation of remedial measures to treat, remove or otherwise manage the contamination found on and off-site and the implementation of on-site management controls to mitigate future off-site property impacts. Most of the contamination at Remotes' sites is associated with historic spills of diesel fuel.

LAR projects are normally planned to coincide with major capital projects such as generation upgrades and extend over multiple years. As such, variances in year over year expense are typical, based on the timing of these discrete projects. As these projects are normally undertaken with the involvement of the local First Nations, negotiations are required and project delays can occur. The decrease between the 2013 OEB-approved amounts and 2013 actual amounts is a result of a delay in the remediation of Pikangikum, Attawapiskat and Webequie, which is partially offset by higher costs than planned in Sachigo. The remediation project at Sandy Lake started earlier than planned and was substantially completed in 2014, leading to a decrease in cost in 2015. Differences between the planned and actual expenditures approved as part of Remotes' revenue requirement flow through the RRRP account, which is further discussed in Exhibit F1, Tab 1, Schedule 1. The duration and cost have been impacted by lengthy negotiations on sites where multiple parties are involved and agreement of responsibility is required, funding constraints from other parties, weather restrictions, and the inability to put the work out for competitive bidding.

## 4.0 LAND ASSESSMENT REMEDIATION PROGRAM

Hydro One Remotes reviews and updates its environmental liability pertaining to its LAR program on an annual basis to determine if any revisions are required to its environmental provisions and related regulatory assets. In 2016, the provision assumptions were reviewed for significant changes in work program plans (e.g. quantity of contaminated sites, extent of contamination, the year in which certain sites are anticipated to become grid connected), including costs and timing for monitoring and remediation, and changes in regulations. No major regulatory changes occurred in 2016. This review encompasses an assessment of the current state of applicable regulations as well as the sufficiency and accuracy of the current dollar cost estimate of performing the work and any revisions to the assumed pattern of expected future cash flows that give rise to the obligation's present value. Expected future cash flows are compiled by experienced Remotes staff and are reviewed by management at Hydro One Networks Inc. and Remotes. Remotes' environmental liabilities consist of the present value of LAR. The same value is used to record the related environmental regulatory asset. The Board accepted this accounting treatment for Remotes, in EB-2005-0020, EB-2008-0232 and in EB-2012-0137.

Remotes confirmed significant increases to the provision consistent with changes in the scope and timing of remediation work and the impact of the grid connection. The Remotes LAR provision was increased in 2016 by $25.7 million (present value). The duration of the program was also extended a further 17 years (originally 2027) to the period ending 2044 to accommodate the additional work. The LAR provision is based on the most reliable information currently available and is mainly driven by revisions in the estimated scope of site remediation, the most recent information available for the costs of remediation, and an increase to annual monitoring costs due to remediation timing. The impact of grid connection is expected to occur in 2024 for ten of the communities that Remotes currently serves, in which the generating stations will be used as backup until the end of their useful lives. The generating stations at the road access sites will continue until the end of their useful lives. There are multiple moving parts with respect to grid connection of the communities and therefore the timing or use of current generation assets may be impacted by future decisions by Indigenous and Northern Affairs Canada, provincial government, OEB, and the IESO. If and when it is, it will be reflected in the provision. Monitoring costs are incurred until a site can be remediated, after which time they continue for two more years in order to ensure that the site is fully remediated. Remediation cannot occur until the station and its components are removed from the site.

At the end of 2016 the provision reflects what is reliably determinable based on facts known at that date and assumptions based on prior experience.

# INCOME TAXES AND PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

## 1.0 INTRODUCTION

This Exhibit explains how Remotes calculates its income tax expenses for the purposes of rate recovery. Exhibit D2, Tab 8, Schedules 1 to 4 contain detailed calculations for rate recovery purposes of income tax liabilities, supporting reconciliations, as needed, as well as copies of Remotes's December 31, 2013, December 31, 2014, October 31, 2015, November 4, 2015, December 31, 2015 and December 31, 2016 tax returns at Exhibit D2, Tab 9. The information provided in this Application is consistent with section 2.8.11 of the Filing Requirements. Material exceptions have been identified and explained.

## 2.0 DEPARTURE FROM PILS REGIME

Under the *Electricity Act, 1998* (Ontario), as a Crown-owned company exempted under section 149(1) of the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (Federal Tax Regime) from paying corporate income taxes, Remotes was obligated to make payments in lieu of corporate income taxes ("PILs") to the Ontario Electricity Financial Corporation.

Effective as of October 31, 2015, in connection with a public offering of its parent companies shares (Hydro One), Remotes was no longer subject to this exemption and exited the PILs regime. Under the *Income Tax Act*, Remotes was deemed to have disposed of its assets at fair market value at that time and immediately re-acquired them at the same value. Remotes was obligated to pay a one-time PILs departure tax of approximately $5 million based on an estimated gain under the *Electricity Act, 1998*.

Neither the departure tax nor the change in tax regime will have any impact on ratepayers. For regulatory purposes, income tax expenses will continue to be calculated according to the method prescribed by the Board's 2006 EDR Tax Model and 2006 EDR Handbook, Section 7.1 "OEB 2006 Regulatory Taxes Expense Methodology".

The tax amounts included in rates relate solely to the estimated current tax liability associated with the regulatory net income before tax, based on the applicable statutory tax rates for the year. Future taxes reflect the future tax liabilities/assets associated with timing differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. These are not taken into consideration. When future income taxes become payable or receivable, it is expected that they will be included in the rates approved by the Board and recovered from customers at that time.

## 3.0 INCOME TAX RATE (FEDERAL AND ONTARIO):

A combined income tax rate of 26.5% has been used for the 2018 test year, comprised of a federal rate of 15% and a provincial rate of 11.5%. Due to the way rates are set for Remotes' customers, any variance between actual taxes payable and forecast taxes, as a result of tax policy changes or rate changes for income tax or capital cost allowance will be captured in the RRRP variance account, described further in Exhibit H1, Tab 1, Schedules 1.

## 4.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between the regulatory Net Income Before Tax ("NIBT") and taxable income for the 2018 test year is provided in Exhibit D2, Tab 8, Schedules 1 and 2. This Schedule contains the income tax computation. It also shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation and capital cost allowance ("CCA").

Reconciliation between the accounting NIBT and taxable income for the historical years 2013, 2014, 2015 and 2016 is also provided in Exhibit D2, Tab 8, Schedules 3 to 4. In order to make it easier to follow these reconciliations, Remotes has placed these adjustments into the following five categories:

1) recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement, or for which appropriate tax adjustments are made (for example, depreciation versus capital cost allowance ("CCA");
2) deferral accounts not included in the revenue requirement;
3) reversal of accounting adjustments not included in the revenue requirement;
4) recurring items not in the revenue requirement; and
5) items whose impact is immaterial in total, and as such, have not been included in the Remote's investment plan.

## 5.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of Remotes taxable income for regulatory purposes is the NIBT as shown on the utility's income statement for the year. The NIBT is prepared using U.S. Generally Accepted Accounting Principles, but taxable income is computed using the relevant tax legislation, interpretations and assessment practices. Therefore, many adjustments are typically made to the NIBT to arrive at taxable income. Essentially, the NIBT is increased by amounts that are not deductible for tax purposes. This includes items such as depreciation, contingent liabilities, accounting losses, accounting provisions such as Other Post-Employment Benefits ("OPEB") and revenue that has been received but not recognized for accounting purposes (for example, income received with respect to a deferral account that has been set-up on the balance sheet rather than shown as additional income on the income statement). On the other hand, the NIBT is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT. This includes items such as CCA, the deductible portion of capitalized overhead, accounting gains and OPEB payments. Such reductions also include expenses incurred for which a deferral account has been set up on the balance sheet, rather than shown as a deduction through the income statement.

Consequently, it is imperative that the NIBT be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes.

## 6.0 TREATMENT OF DEFERRAL ACCOUNTS (REGULATORY ASSETS AND LIABILITIES)

Deferral accounts are typically recognized by utilities' balance sheets for foregone revenue or for incurred expenses, for which recovery will be sought from ratepayers through future rates. The Board determines disposition of the deferral accounts.

For example, as shown in Table 1, assuming that a 26.5% tax rate is used and a $100 expense is incurred, the utility will be allowed to deduct the $100 in computing taxable income for the year in which the expense has been incurred. If the Board subsequently approves recovery of this expense over a two-year period through a rate rider, the income will be included in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income or expense has been taxed or deducted in different years.

**Table 1**

**Example: Income Tax Treatment of Deferral Account Disposition**

| | Year 1 | Year 2 | Year 3 | CUM |
|---|---|---|---|---|
| **Income (deduction)** | (100) | 50 | 50 | NIL |
| **Tax Refund (payable)** | 26.5 | (13.25) | (13.25) | NIL |
| **Cash Inflow (outflow)** | (73.5) | 36.75 | 36.75 | NIL |

Therefore, deferral accounts have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. This conclusion is consistent with the "2006 EDR Handbook Report of the Board" issued May 11, 2005, (page 61), that states:

> “A PILS or tax provision is not needed for the recovery of deferredy asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their returns. The Handbook will reflect this treatment.”

## 7.0 CONTINGENT LIABILITIES/ACCOUNTING RESERVES

Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future (such as obsolescence provisions, lawsuits, staff reductions), the provision will reduce the NIBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed by the utility for reasonableness based on all available information. The balance may be adjusted upward or downward, with NIBT either decreasing or increasing, respectively.

However, for tax purposes, a contingent liability or accounting reserve is not deductible. Rather, the amount will only be deductible (or capitalized) in computing taxable income for the taxation year in which the obligation has actually been settled. Therefore, to the extent that the current year NIBT has been increased (or decreased) by the contingent liability or accounting reserve provision, the NIBT must be adjusted to reverse the increase (or decrease) in computing taxable income.

Remotes has not adjusted the 2018 through 2022 NIBT for contingent liabilities in computing taxable income since no changes were forecast in the contingent liability balances for 2018 through 2022. Therefore, such amounts are not included in the tax computation for purposes of the revenue requirement.

The combined (federal and provincial) enacted income tax rates are as set out in Table 2.

**Table 2**

**Combined Income Tax Rates**

| | **Historical** | | | | **Bridge** | **Test** | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
| **Federal Tax Rate (%)** | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| **Provincial Tax Rate (%)** | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 | 11.5 |
| **Total Statutory Tax Rate (%)** | **26.5** | **26.5** | **26.5** | **26.5** | **26.5** | **26.5** | **26.5** | **26.5** | **26.5** | **26.5** |

## 8.0 INTEGRITY CHECKS

Remotes has performed the integrity checks set described in 2.4.5.2 of the Filing requirements.

## 2017 REGULATORY TAX ADJUSTMENT

As a result of the Initial Public Offering ("IPO") of Hydro One Limited, Remotes exited the PILS regime. This triggered a deemed disposition of all of its assets at Fair Market Value ("FMV").

As a result of the deemed disposition on IPO, Remotes was not able to claim the capital cost allowance ("CCA") for the January 1 to October 31, 2015 period for tax purposes. It was discovered that the additional tax expense from not claiming CCA was not returned to rate payers – which resulted in additional amounts being collected in rates (via the Rural and Remote Rate Protection (RRRP) account).

The rate payers should not be impacted as a result of the IPO. Any tax deductions that were lost as a result of the IPO should stay with the shareholder as opposed to being included in rates to keep the rate payers whole.

Tax deductions lost as a result of the IPO were factored into rates resulting in lower taxes and a higher net income in Remotes for 2015. As Remotes operates a break-even business, this higher net income must be returned to rate payers through the RRRP variance account. As a result, the CCA from January 1, 2015 to October 31, 2015 will be claimed for rate filing purposes.

As Remotes' net income is nil, the overstatement of taxes resulted in the RRRP account being overstated by $682K. Consequently, the RRRP account has been adjusted lower by $682K.

# PROPERTY TAXES AND CROWN LEASE PAYMENTS

## 1.0 SUMMARY OF PROPERTY TAXES AND CROWN LEASE PAYMENTS

This Exhibit describes property taxes and crown lease payments made in respect of Remotes. These costs are externally imposed and are summarized in Table 1. The property taxes and crown lease payments are included as part of the costing of work as described in Exhibit D1, Tab 5, Schedule 1.

**Table 1**
**Property Taxes and Crown Lease Payments (in $K)**

| **Category** | **Board Approved** | **Historic (Actuals)** | | | | **Bridge** | **Test** |
|---|---|---|---|---|---|---|---|
| | **2013** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Property Taxes | 50 | 49 | 48 | 48 | 48 | 55 | 55 |
| Crown Lease Payments | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| **Total** | **58** | **57** | **56** | **56** | **56** | **63** | **63** |

Remotes property taxes are regulated under the *Electricity Act 1998*, the *Municipal Act 2001*, and the *Assessment Act 1990*. Property taxes are paid to the City of Thunder Bay each year on the service centre site located at 680 Beaverhall Place. The total assessed property values are assigned by the Municipal Property Assessment Corporation and updated using the same schedule as the rest of the province.

Remotes pays a nominal fee for the right to use Crown land.

As Table 1 shows, actual payments are materially in line with approved levels.

The test year property tax forecast is based on most recent property tax information available.

# HYDRO ONE REMOTE COMMUNITIES INC.

## Cost of Service

Historical (2013, 2014, 2015, 2016), Bridge (2017) and Test (2018) Years
Year Ending December 31
(in $K)

| Line No. | Particulars | 2013 (a) | 2014 (b) | 2015 (c) | 2016 (e) | 2017 (f) | 2018 (f) |
|---|---|---|---|---|---|---|---|
| 1 | Total Operation, Maintenance & Administrative Expenses | 45,212 | 45,939 | 41,113 | 43,497 | 48,385 | 50,143 |
| 2 | Depreciation & Amortization Expenses | 4,809 | 4,623 | 4,902 | 4,618 | 5,081 | 4,608 |
| 3 | Capital Taxes | - | - | - | - | - | - |
| 4 | Income Taxes (Note1) | (700) | (56) | (301) | 440 | (82) | (69) |
| 5 | **Total Cost of Service** | **49,321** | **50,506** | **45,714** | **48,555** | **53,384** | **54,682** |

Note 1: Historic years calculated per tax returns; Bridge year per tax return projection; Test year based on revenue requirement

**HYDRO ONE REMOTE COMMUNITIES INC.**
Mapping OM&A Expenditures to Grouped USofA Accounts
Historical (2013, 2014, 2015 and 2016), Bridge (2017) and Test (2018) Years
As at December 31
(in $K)

| Line No. | Minimum USofA Grouping | Account Numbers | Approved 2013 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Generation - Operation | 4510, 4550, 4555 | 28,640 | 29,874 | 30,129 | 27,587 | 28,027 | 31,304 | 32,519 |
| 2 | Generation - Maintenance | 4610, 4635 | 6,012 | 8,648 | 9,932 | 8,610 | 9,574 | 11,392 | 11,640 |
| 3 | Generation - Other Power Supply | 4708 | 1,980 | - | - | - | 61 | - | - |
| 4 | Distribution Expenses - Operation | 5085 | 301 | 62 | 80 | 199 | 212 | 111 | 116 |
| 5 | Distribution Expenses- Maintenance | 5120, 5125, 5130, 5135, 5175 | 2,679 | 1,399 | 1,799 | 2,216 | 1,780 | 2,008 | 2,087 |
| 6 | Customer Care (Billing and Collecting) | 5310, 5315, 5320, 5335 | 1,903 | 3,064 | 1,731 | 628 | 1,876 | 1,892 | 1,999 |
| 7 | Community Relations | 5410, 5415, 5420 | 750 | 520 | 554 | 291 | 138 | 379 | 305 |
| 8 | Administrative and General Expenses | 5615, 5625, 5655, 5675, 6205 | 1,157 | 1,439 | 1,542 | 1,317 | 1,487 | 1,164 | 1,342 |
| 8 | External Costs | 4330 | 61 | 206 | 172 | 265 | 342 | 135 | 135 |
| 10 | **Total OM&A** | | **43,483** | **45,212** | **45,939** | **41,113** | **43,497** | **48,385** | **50,143** |

# Appendix 2-JA
## Summary of Recoverable OM&A Expenses
## (in $K)

| | Last Rebasing Year (2013 Board-Approved) | Last Rebasing Year (2013 Actuals) | 2014 Actuals | 2015 Actuals | 2016 Actuals | 2017 Bridge Year | 2018 Test Year |
|---|---|---|---|---|---|---|---|
| ***Reporting Basis*** | **USGAAP** | **USGAAP** | **USGAAP** | **USGAAP** | **USGAAP** | **USGAAP** | **USGAAP** |
| Generation Operations | $ 30,620 | $ 29,874 | $ 30,129 | $ 27,587 | $ | $ 31,304 | $ 32,519 |
| Generation Maintenance | $ 6,012 | $ 8,648 | $ 9,932 | $ 8,610 | $ 9,574 | $ 11,392 | $ 11,640 |
| Distribution Operations | $ 300 | $ 62 | $ 80 | $ 199 | $ 28,088 212 | $ 111 | $ 116 |
| Distribution Maintenance | $ 2,680 | $ 1,399 | $ 1,799 | $ 2,216 | $ 1,780 | $ 2,008 | $ 2,087 |
| **SubTotal** | **$ 39,612** | **$ 39,983** | **$ 41,940** | **$ 38,612** | **$ 39,654** | **$ 44,815** | **$ 46,362** |
| %Change (year over year) | | | 4.9% | -7.9% | 2.7% | 16.1% | 3.5% |
| %Change (Test Year vs Last Rebasing Year - Actual) | | | | | | | 16.0% |
| Billing and Collecting | $ 1,903 | $ 3,064 | $ 1,731 | $ 628 | $ 1,876 | $ 1,892 | $ 1,999 |
| Community Relations | $ 750 | $ 520 | $ 554 | $ 291 | $ 138 | $ 379 | $ 305 |
| Administrative and General | $ 1,218 | $ 1,645 | $ 1,714 | $ 1,582 | $ 1,829 | $ 1,299 | $ 1,477 |
| **SubTotal** | **$ 3,871** | **$ 5,229** | **$ 3,999** | **$ 2,501** | **$** | **$ 3,570** | **$ 3,781** |
| %Change (year over year) | | | -23.5% | -37.5% | **3,843** 53.7% | 42.7% | 5.9% |
| %Change (Test Year vs Last Rebasing Year - Actual) | | | | | | | -27.7% |
| **Total** | **$ 43,483** | **$ 45,212** | **$ 45,939** | **$ 41,113** | **$ 43,497** | **$ 48,385** | **$ 50,143** |
| %Change (year over year) | | | 1.6% | -10.5% | 5.8% | 11.2% | 3.6% |

| | Last Rebasing Year (2013 Board-Approved) | Last Rebasing Year (2013 Actuals) | 2014 Actuals | 2015 Actuals | 2016 Actuals | 2017 Bridge Year | 2018 Test Year |
|---|---|---|---|---|---|---|---|
| Generation Operations | $ 30,620 | $ 29,874 | $ 30,129 | $ 27,587 | $ | $ 31,304 | $ 32,519 |
| Generation Maintenance | $ 6,012 | $ 8,648 | $ 9,932 | $ 8,610 | $ 9,574 | $ 11,392 | $ 11,640 |
| Distribution Operations | $ 300 | $ 62 | $ 80 | $ 199 | $ 28,088 212 | $ 111 | $ 116 |
| Distribution Maintenance | $ 2,680 | $ 1,399 | $ 1,799 | $ 2,216 | $ 1,780 | $ 2,008 | $ 2,087 |
| Billing and Collecting | $ 1,903 | $ 3,064 | $ 1,731 | $ 628 | $ 1,876 | $ 1,892 | $ 1,999 |
| Community Relations | $ 750 | $ 520 | $ 554 | $ 291 | $ 138 | $ 379 | $ 305 |
| Administrative and General | $ 1,218 | $ 1,645 | $ 1,714 | $ 1,582 | $ 1,829 | $ 1,299 | $ 1,477 |
| **Total** | **$ 43,483** | **$ 45,212** | **$ 45,939** | **$ 41,113** | **$ 43,497** | **$ 48,385** | **$ 50,143** |
| %Change (year over year) | | | 1.6% | -10.5% | 5.8% | 11.2% | 3.6% |

| | Last Rebasing Year (2013 Board-Approved) | Last Rebasing Year (2013 Actuals) | Variance 2013 BA – 2013 Actuals | 2014 Actuals | Variance 2014 Actuals vs. 2013 Actuals | 2015 Actuals | Variance 2015 Actuals vs. 2014 Actuals | 2016 Actuals | Variance 2016 Actuals vs. 2015 Actuals | 2017 Bridge Year | Variance 2017 Bridge vs. 2016 Actuals | 2018 Test Year | Variance 2018 Test vs. 2017 Bridge |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Generation Operations** | $ 30,620 | $ 29,874 | -$ 746 | $ 30,129 | $ 255 | $ 27,587 | -$ 2,542 | $ 28,088 | $ 501 | $ 31,304 | $ 3,216 | $ 32,519 | $ 1,215 |
| **Generation Maintenance** | $ 6,012 | $ 8,648 | $ 2,636 | $ 9,932 | $ 1,284 | $ 8,610 | -$ 1,322 | $ 9,574 | $ 964 | $ 11,392 | $ | $ 11,640 | $ 248 |
| **Distribution Operations** | $ 300 | $ 62 | -$ 238 | $ 80 | $ | $ 199 | $ 119 | $ 212 | $ 13 | $ 111 | -$ 1,818 101 | $ 116 | $ 5 |
| **Distribution Maintenance** | $ 2,680 | $ 1,399 | -$ 1,281 | $ 1,799 | $ 18 400 | $ 2,216 | $ 417 | $ 1,780 | -$ 436 | $ 2,008 | $ | $ 2,087 | $ 79 |
| **Billing and Collecting** | $ 1,903 | $ 3,064 | $ 1,161 | $ 1,731 | -$ 1,333 | $ 628 | -$ 1,103 | $ 1,876 | $ 1,248 | $ 1,892 | $ | $ 1,999 | $ 107 |
| **Community Relations** | $ 750 | $ 520 | -$ 230 | $ 554 | $ | $ 291 | -$ 263 | $ 138 | -$ 153 | $ 379 | $ 228 241 | $ 305 | -$ 74 |
| **Administrative and General** | $ 1,218 | $ 1,645 | $ 427 | $ 1,714 | $ 34 658 | $ 1,582 | -$ 132 | $ 1,829 | $ 247 | $ 1,299 | -$ 16 | $ 1,477 | $ 178 |
| **Total OM&A Expenses** | $ 43,483 | $ 45,212 | $ 1,729 | $ 45,939 | $ 1,316 | $ 41,113 | -$ 4,826 | $ 43,497 | $ 2,384 | $ 48,385 | $ 4,888 | $ 50,143 | $ 1,758 |
| **Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)** | | | | | | | | | | | 530 | | |
| **Total Recoverable OM&A Expenses** | $ 43,483 | $ 45,212 | $ 1,729 | $ 45,939 | $ 1,316 | $ 41,113 | -$ 4,826 | $ 43,497 | $ 2,384 | $ 48,385 | $ 4,888 | $ 50,143 | $ 1,758 |
| **Variance from previous year** | | | | $ 727 | | -$ 4,826 | | $ 2,384 | | $ 4,888 | | $ | |
| **Percent change (year over year)** | | | | 2% | | -11% | | 6% | | 11% | | 4% | |
| **Percent Change: Test year vs. Most Current Actual** | | | | | | | | 15.28% | | | | 1,758 | |
| **Simple average of % variance for all years** | | 4,045 | | | | | | 10.91% | | | | | 2% |
| **Compound Annual Growth Rate for all years** | | | | | | | | -56.54% | | | | | 2.1% |
| **Compound Growth Rate (2016 Actuals vs. 2013 Actuals)** | | | | | | | | -1.28% | | | | | |

**Note:**

**1** "BA" = Board-Approved

**2** If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

**3** Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

# Appendix 2-JB
# Recoverable OM&A Cost Driver Table
# (in $K)

| OM&A | Last Rebasing Year (2013 Actuals) | 2014 Actuals | 2015 Actuals | 2016 Actuals | 2017 Bridge Year | 2018 Test Year |
|---|---|---|---|---|---|---|
| *Reporting Basis* | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP |
| **Opening Balance** | $ 43,483 | $ 45,212 | $ 45,939 | $ 41,113 | $ 43,497 | $ 48,385 |
| **Generation Operations** | | | | | | |
| Sustainment Projects - Operations | -$ 326 | -$ 11 | $ 222 | -$ 53 | $ 468 | $ 80 |
| Environment | $ 59 | -$ 35 | -$ 145 | $ 74 | -$ 7 | $ 21 |
| Sustainment Projects - Operations | $ 1,501 | $ 302 | -$ 2,618 | $ 420 | $ 2,816 | $ 1,115 |
| Sustainment Projects - Operations | -$ 1,980 | $ - | $ - | $ 61 | -$ 61 | $ - |
| | | | | | | |
| **Generation Maintenance** | | | | | | |
| Sustainment Projects - Gx Maintenance | $ 2,439 | $ 991 | -$ 970 | $ 902 | $ 1,343 | $ 229 |
| Safety Improvements | $ 67 | $ 173 | -$ 296 | -$ 187 | $ 386 | $ - |
| RET Improvements | -$ 36 | -$ 6 | $ 7 | -$ 6 | $ 7 | $ - |
| Environmental Improvements | -$ 2 | -$ 52 | $ 152 | $ 38 | -$ 118 | $ 2 |
| Engineering Investigations | $ 167 | $ 179 | -$ 215 | $ 217 | $ 199 | $ 17 |
| | | | | | | |
| **Distribution Maintenance** | | | | | | |
| Distribution Sustainment | -$ 1,517 | $ 415 | $ 535 | -$ 423 | $ 128 | $ 84 |
| | | | | | | |
| **Billing and Collecting** | | | | | | |
| Customer Care | $ 1,161 | -$ 1,331 | -$ 1,104 | $ 1,247 | $ 16 | $ 108 |
| | | | | | | |
| **Community Relations** | | | | | | |
| Community Relations | -$ 231 | $ 34 | -$ 263 | -$ 153 | $ 241 | -$ 75 |
| | | | | | | |
| **Administrative and General** | | | | | | |
| Shared Services and Other Admin Costs | $ 282 | $ 102 | -$ 224 | $ 170 | -$ 323 | $ 177 |
| External Costs | $ 145 | -$ 34 | $ 93 | $ 77 | -$ 207 | $ - |
| | | | | | | |
| **Closing Balance** | $ 45,212 | $ 45,939 | $ 41,113 | $ 43,497 | $ 48,385 | $ 50,143 |

**Notes:**

**1** For each year, a detailed explanation for each cost driver and associated amount is required in Exhibit 4.
**2** For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

**3** If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

**4** Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

**Appendix 2-JC**
**OM&A Programs Table**
**(in $K)**

| Programs | Last Rebasing Year (2013 Board-Approved) | Last Rebasing Year (2013 Actuals) | 2014 Actuals | 2015 Actuals | 2016 Actuals | 2017 Bridge Year | 2018 Test Year | Variance (Test Year vs. 2016 Actuals) | Variance (Test Year vs. Last Rebasing Year (2013 Board-Approved) |
|---|---|---|---|---|---|---|---|---|---|
| *Reporting Basis* | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP |
| **Generation Expenses Operations** | | | | | | | | | |
| 4510 - Fuel | 24,067 | 25,568 | 25,869 | 23,250 | 23,669 | 26,485 | 27,600 | 3,931 | 3,533 |
| 4550 - Generation Expense | 3,477 | 3,151 | 3,140 | 3,362 | 3,309 | 3,777 | 3,856 | 547 | 379 |
| 4555 - Miscellaneous Power Generation Expenses | 1,096 | 1,155 | 1,120 | 975 | 1,049 | 1,042 | 1,063 | 14 | -33 |
| 4708 - Charges - WMS | 0 | 0 | 0 | 0 | 61 | 0 | 0 | -61 | 0 |
| **Sub-Total** | 28,640 | 29,874 | 30,129 | 27,587 | 28,088 | 31,304 | 32,519 | 4,431 | 3,879 |
| **Generation Expenses Maintenance** | | | | | | | | | |
| 4610 - Maintenance of Structures | 933 | 1,529 | 1,719 | 1,469 | 1,557 | 1,466 | 1,491 | -66 | 558 |
| 4635 - Maintenance of Generating and Electric Plant | 5,079 | 7,119 | 8,213 | 7,141 | 8,017 | 9,926 | 10,149 | 2,132 | 5,070 |
| **Sub-Total** | 6,012 | 8,648 | 9,932 | 8,610 | 9,574 | 11,392 | 11,640 | 2,066 | 5,628 |
| **Other Power Supply Expenses** | | | | | | | | | |
| 4705 - Power Purchased | 1,980 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1,980 |
| **Sub-Total** | 1,980 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1,980 |
| **Distribution Expense Operations** | | | | | | | | | |
| 5085 - Miscellaneous Distribution Expense | 301 | 62 | 80 | 199 | 212 | 111 | 116 | -96 | -185 |
| **Sub-Total** | 301 | 62 | 80 | 199 | 212 | 111 | 116 | -96 | -185 |
| **Distribution Expense Maintenance** | | | | | | | | | |
| 5120 - Maintenance of Poles, Towers and Fixtures | 695 | 500 | 633 | 754 | 703 | 719 | 751 | 48 | 56 |
| 5125 - Maintenance of Overhead Conductors and Devices | 556 | 391 | 512 | 602 | 562 | 575 | 601 | 39 | 45 |
| 5130 - Maintenance of Overhead Services | 139 | 100 | 127 | 151 | 141 | 144 | 150 | 9 | 11 |
| 5135 - Overhead Distribution Lines and Feeders - Right of Way | 1,174 | 313 | 392 | 549 | 262 | 448 | 457 | 195 | -717 |
| 5175 - Maintenance of Meters | 116 | 95 | 135 | 160 | 112 | 122 | 128 | 16 | 12 |
| **Sub-Total** | 2,680 | 1,399 | 1,799 | 2,216 | 1,780 | 2,008 | 2,087 | 307 | -593 |
| **Collecting and Billing** | | | | | | | | | |
| 5310 - Meter Reading Expense | 347 | 286 | 404 | 479 | 335 | 367 | 383 | 48 | 36 |
| 5315 - Customer Billing | 1,123 | 2,542 | 1,195 | 964 | 1,202 | 1,169 | 1,221 | 19 | 98 |
| 5320 - Collecting | 385 | 16 | 307 | 290 | 360 | 321 | 335 | -25 | -50 |
| 5335 - Bad Debt Expense | 48 | 220 | -175 | -1,105 | -21 | 35 | 60 | 81 | 12 |
| 5410 - Community Relations - Sundry | 133 | 79 | 89 | 100 | 67 | 218 | 139 | 72 | 6 |
| 5415 - Energy Conservation | 565 | 398 | 404 | 144 | 14 | 110 | 112 | 98 | -453 |
| 5420 - Community Safety Program | 53 | 43 | 61 | 47 | 57 | 51 | 54 | -3 | 1 |
| 5425 - Misc Customer Service and Informational Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Sub-Total** | 2,654 | 3,584 | 2,285 | 919 | 2,014 | 2,271 | 2,304 | 290 | -350 |
| **Administration General Expenses** | | | | | | | | | |
| 5615 - General Administrative Salaries and Expenses | 1,429 | 1,441 | 1,645 | 1,670 | 1,778 | 1,572 | 1,574 | -204 | 145 |
| 5625 - Administrative Expense Transferred - Credit | -456 | -320 | -342 | -556 | -410 | -562 | -448 | -38 | 8 |
| 5655 - Regulatory Expenses | 132 | 262 | 138 | 142 | 68 | 103 | 165 | 97 | 33 |
| 5665 - Miscellaneous General Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5675 - Maintenance of General Plant | 0 | 12 | 50 | 10 | 0 | 0 | 0 | 0 | 0 |
| **Sub-Total** | 1,105 | 1,395 | 1,491 | 1,266 | 1,436 | 1,113 | 1,291 | -145 | 186 |
| **Other Deductions** | | | | | | | | | |
| 4330 - Costs and Expenses of Merchandising | 60 | 206 | 172 | 265 | 342 | 133 | 133 | -209 | 73 |
| 6205 - Donations | 51 | 44 | 51 | 51 | 51 | 53 | 53 | 2 | 2 |
| **Sub-Total** | 111 | 250 | 223 | 316 | 393 | 186 | 186 | -207 | 75 |
| **Miscellaneous** | | | | | | | | 0 | 0 |
| **Total** | **43,483** | **45,212** | **45,939** | **41,113** | **43,497** | **48,385** | **50,143** | **6,646** | **6,660** |

***Notes:***

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

# Appendix 2-L
## Recoverable OM&A Cost per Customer and per FTE [1]
## (in $K)

| | Last Rebasing Year - 2013- Board Approved | Last Rebasing Year - 2013- Actual | 2014 Actuals | 2015 Actuals | 2016 Actuals | 2017 Bridge Year | 2018 Test Year |
|---|---|---|---|---|---|---|---|
| Reporting Basis | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP | USGAAP |
| OM&A Costs | | | | | | | |
| O&M | $ 42,267 | $ 43,567 | $ 44,225 | $ 39,531 | $ 41,668 | $ 47,086 | $ 48,666 |
| Admin Expenses | $ 1,216 | $ 1,645 | $ 1,714 | $ 1,582 | $ 1,829 | $ 1,299 | $ 1,477 |
| Total Recoverable OM&A from Appendix 2-JB [5] | $ 43,483 | $ 45,212 | $ 45,939 | $ 41,113 | $ 43,497 | $ 48,385 | $ 50,143 |
| Number of Customers [2,4] | 3,529 | 3,513 | 3,546 | 3,530 | 3,554 | 3,627 | 3,762 |
| Number of FTEs [3,4] | 48 | 58.33 | 58.68 | 58.22 | 61.83 | 60.3 | 60.3 |
| Customers/FTEs | 73.52 | 60.23 | 60.43 | 60.63 | 57.48 | 60.15 | 62.39 |
| OM&A cost per customer | | | | | | | |
| O&M per customer | 11.97704732 | 12.40165101 | 12.47179921 | 11.19858357 | 11.72425436 | 12.98207885 | 12.93620415 |
| Admin per customer | 0.344573534 | 0.468260746 | 0.483361534 | 0.44815864 | 0.514631401 | 0.358147229 | 0.392610314 |
| Total OM&A per customer | 12.32162086 | 12.86991176 | 12.95516074 | 11.64674221 | 12.23888576 | 13.34022608 | 13.32881446 |
| OM&A cost per FTE | | | | | | | |
| O&M per FTE | 880.5625 | 746.9055375 | 753.66394 | 678.993473 | 673.9123403 | 780.8623549 | 807.0646766 |
| Admin per FTE | 25.33333333 | 28.20161152 | 29.20927062 | 27.17279285 | 29.58110949 | 21.54228856 | 24.49419569 |
| Total OM&A per FTE | 905.8958333 | 775.107149 | 782.8732106 | 706.1662659 | 703.4934498 | 802.4046434 | 831.5588723 |

**Notes:**

1 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers must be identified. Should correspond with data provided in Appendix 2-IB

3 The method of calculating the number of FTEs must be identified. See also Appendix 2-K

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

5 For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

**Appendix 2-N**
**Shared Services and Corporate Cost Allocation [1]**
**Years: 2013-2018**
**(in $K)**

### Shared Services

| Name of Company | | Service Offered | | Pricing Methodology | 2013 | | 2014 | | 2015 | | 2016 | | 2017 | | 2018 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| From | To | | | | Price for the Service | Cost for the Service | Price for the Service | Cost for the Service | Price for the Service | Cost for the Service | Price for the Service | Cost for the Service | Price for the Service | Cost for the Service | Price for the Service | Cost for the Service |
| | | | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| HONI | Remotes | Utility Operation Services | • Fleet<br>• Forestry<br>• Lines<br>• Engineering | Cost Based | 2,468 | **2,468** | 1,799 | **1,799** | 2,077 | **2,077** | 1,859 | **1,859** | 1,640 | **1,640** | 1,649 | **1,649** |
| HONI | Remotes | Supply Chain Services | • Purchasing | Cost Based | 76 | **76** | 76 | **76** | 76 | **76** | 76 | **76** | 76 | **76** | 76 | **76** |
| HONI | Remotes | Transfer Price Charges for HONI Assets | • System Services<br>• Lease of Computer Equipment | Allocation Model | 219 | **219** | 299 | **299** | 299 | **299** | 276 | **276** | 261 | **261** | 261 | **261** |

### Corporate Cost Allocation

| Name of Company | | Service Offered | | Pricing Methodology | % of Corporate Costs Allocated | Amount Allocated | % of Corporate Costs Allocated | Amount Allocated | % of Corporate Costs Allocated | Amount Allocated | % of Corporate Costs Allocated | Amount Allocated | % of Corporate Costs Allocated | Amount Allocated | % of Corporate Costs Allocated | Amount Allocated |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| From | To | | | | % | $ | % | $ | % | $ | % | $ | % | $ | % | $ |
| HOI | Remotes | General Counsel & Secretary | • Corporate Secretariat<br>• Corporate Management | CC Allocation Model | 2.5% | **23** | 2.5% | **21** | 2.4% | **21** | 2.4% | **23** | 1.2% | **28** | 1.2% | **29** |
| HOI | Remotes | President/CEO/Chairman/Board | • President/CEO Office<br>• Chair<br>• Board | CC Allocation Model | 0.5% | **18** | 0.4% | **19** | 0.3% | **19** | 0.3% | **48** | 2.4% | **21** | 2.4% | **21** |
| HOI | Remotes | Chief Financial Office Services | • CFO Office | CC Allocation Model | 1.1% | **8** | 1.1% | **8** | 1.1% | **8** | 1.1% | **22** | 0.3% | **13** | 0.3% | **13** |
| HONI | Remotes | General Counsel & Secretary Services | • Law<br>• Corporate Secretariat<br>• Regulatory Affairs | CC Allocation Model | 1.1% | **329** | 1.2% | **343** | 1.2% | **255** | 1.2% | **405** | 0.8% | **383** | 0.8% | **388** |
| HONI | Remotes | Financial Services | • Corporate Controller<br>• Treasury<br>• Tax<br>• Decision Support<br>• Internal Audit and Risk Management | CC Allocation Model | 0.7% | **176** | 0.7% | **211** | 0.7% | **210** | 0.7% | **279** | 1.2% | **247** | 1.2% | **236** |
| HONI | Remotes | Corporate Services | • Human Resources<br>• Labour Relations<br>• Communications<br>• External Relations<br>• Corporate Security<br>• First Nations & Metis Relations<br>• Information Management | CC Allocation Model | 0.1% | **223** | 0.1% | **297** | 0.1% | **353** | 0.1% | **276** | 0.7% | **269** | 0.7% | **269** |
| HONI | Remotes | Telecom Services | • Telecom Services | CC Allocation Model | 0.7% | **124** | 0.8% | **125** | 0.8% | **140** | 0.8% | **135** | 0.1% | **141** | 0.1% | **141** |
| HONI | Remotes | Other Services | Inergi:<br>• Customer Support<br>• Finance<br>• Settlements<br>• Human Resources<br>• IT | CC Allocation Model | 0.3% | **358** | 0.2% | **351** | 0.2% | **399** | 0.2% | **353** | 0.8% | **263** | 0.8% | **255** |

**Note:**
**1** **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

**Legend:**
"HOI" Hydro One Inc.
"HONI" Hydro One Netwo
"Remotes" Hydro One Remotes Inc.

***Type of Service:*** **Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.**

***Pricing Methodology:*** **Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.**

***% Allocation:*** **The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.**

# Hydro One Remote Communities Inc.
## Comparison of Wages and Salaries

| Year | Representation | Total Pay | Base Pay | Overtime | Incentive Pay | Other Allowances | FTEs |
|---|---|---|---|---|---|---|---|
| 2013 | MCP | 704,673 | 621,242 | 0 | 55,500 | 27,932 | 5.0 |
| | PWU | 3,968,794 | 2,942,923 | 867,611 | 0 | 158,260 | 33.5 |
| | SOCIETY | 1,406,944 | 1,271,554 | 101,746 | 0 | 33,644 | 13.5 |
| | Casual | 973,414 | 561,242 | 319,927 | 0 | 92,245 | 6.4 |
| | **Total** | **7,053,826** | **5,396,961** | **1,289,285** | **55,500** | **312,080** | **58.3** |
| 2014 | MCP | 741,678 | 609,248 | 0 | 71,289 | 61,142 | 5.0 |
| | PWU | 3,820,037 | 2,898,131 | 769,507 | 0 | 152,400 | 34.7 |
| | Society | 1,542,898 | 1,334,880 | 152,649 | 0 | 55,369 | 11.9 |
| | Casual | 1,069,956 | 636,357 | 338,469 | 0 | 95,130 | 7.1 |
| | **Total** | **7,174,570** | **5,478,615** | **1,260,625** | **71,289** | **364,041** | **58.7** |
| 2015 | MCP | 558,677 | 464,304 | - | 73,000 | 21,373 | 3.0 |
| | PWU | 3,927,010 | 2,951,082 | 809,274 | 0 | 166,654 | 33.1 |
| | Society | 1,778,866 | 1,502,631 | 206,151 | 0 | 70,083 | 14.0 |
| | Casual | 1,056,804 | 646,259 | 327,913 | 0 | 82,633 | 8.1 |
| | **Total** | **7,321,357** | **5,564,277** | **1,343,338** | **73,000** | **340,742** | **58.2** |
| 2016 | MCP | 803,740 | 683,090 | 0 | 75,570 | 45,079 | 5.0 |
| | PWU | 4,082,771 | 3,049,037 | 811,977 | 0 | 221,756 | 35.5 |
| | Society | 1,801,594 | 1,566,328 | 168,553 | 0 | 66,713 | 13.0 |
| | Casual | 1,184,316 | 729,858 | 350,319 | 0 | 104,139 | 8.3 |
| | **Total** | **7,872,420** | **6,028,314** | **1,330,849** | **75,570** | **437,688** | **61.8** |
| 2017 | MCP | 819,814 | 696,752 | 0 | 77,081 | 45,981 | 5.0 |
| | PWU | 4,123,599 | 3,079,528 | 820,097 | 0 | 223,974 | 33.7 |
| | Society | 1,810,602 | 1,574,160 | 169,395 | 0 | 67,047 | 14.0 |
| | Casual | 1,196,159 | 737,157 | 353,822 | 0 | 105,180 | 7.6 |
| | **Total** | **7,950,174** | **6,087,596** | **1,343,314** | **77,081** | **442,182** | **60.3** |
| 2018 | MCP | 819,814 | 696,752 | 0 | 77,081 | 45,981 | 5.0 |
| | PWU | 4,164,835 | 3,110,323 | 828,298 | 0 | 226,214 | 33.7 |
| | Society | 1,819,655 | 1,582,030 | 170,242 | 0 | 67,382 | 14.0 |
| | Casual | 1,208,121 | 744,528 | 357,360 | 0 | 106,232 | 7.6 |
| | **Total** | **8,012,424** | **6,133,634** | **1,355,901** | **77,081** | **445,809** | **60.3** |

# Appendix 2-K
## Employee Costs

| | Last Rebasing Year - 2013- Board Approved | Last Rebasing Year - 2013- Actual | 2014 Actuals | 2015 Actuals | 2016 Actuals | 2017 Bridge Year | 2018 Test Year |
|---|---|---|---|---|---|---|---|
| **Number of Employees (FTEs including Part-Time and Casual Employees) [1]** | | | | | | | |
| Management (including executive) | 5.0 | 5.0 | 5.0 | 3.0 | 5.0 | 5.0 | 5.0 |
| Non-Management (union and non-union) [2] | 43.0 | 53.3 | 53.7 | 55.2 | 56.8 | 55.3 | 55.3 |
| Total | **48.0** | **58.3** | **58.7** | **58.2** | **61.8** | **60.3** | **60.3** |
| **Total Salary and Wages including overtime and incentive pay** | | | | | | | |
| Management (including executive) | $ 740,430 | $ 704,673 | $ 741,678 | $ 558,677 | $ 803,740 | $ 819,814 | $ 819,814 |
| Non-Management (union and non-union) [2] | $ 5,026,714 | $ 6,349,153 | $ 6,432,892 | $ 6,762,680 | $ 7,068,681 | $ 7,130,360 | $ 7,192,610 |
| Total | **$ 5,767,145** | **$ 7,053,826** | **$ 7,174,570** | **$ 7,321,357** | **$ 7,872,420** | **$ 7,950,174** | **$ 8,012,424** |
| **Total Benefits (Current + Accrued) [3]** | | | | | | | |
| Management (including executive) | $ 104,355 | $ 126,978 | $ 152,154 | $ 130,301 | $ 141,716 | $ 172,429 | $ 175,678 |
| Non-Management (union and non-union) | $ 737,645 | $ 897,564 | $ 1,061,168 | $ 954,580 | $ 1,071,015 | $ 1,080,038 | $ 1,095,638 |
| Total | **$ 842,000** | **$ 1,024,542** | **$ 1,213,322** | **$ 1,084,881** | **$ 1,212,731** | **$ 1,252,468** | **$ 1,271,315** |
| **Total Compensation (Salary, Wages, & Benefits)** | | | | | | | |
| Management (including executive) | $ 844,785 | $ 831,651 | $ 893,832 | $ 688,978 | $ 945,455 | $ 992,243 | $ 995,492 |
| Non-Management (union and non-union) | $ 5,764,360 | $ 7,246,716 | $ 7,494,060 | $ 7,717,260 | $ 8,139,696 | $ 8,210,398 | $ 8,288,248 |
| Total | **$ 6,609,145** | **$ 8,078,368** | **$ 8,387,892** | **$ 8,406,238** | **$ 9,085,151** | **$ 9,202,641** | **$ 9,283,740** |

**Note:**

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

[2] Board Approved amounts from Last Rebasing Year (2013) did not include Casual Employees.

[3] Current employee benefits, plus Pension and Other Post-Employment Benefits costs, as recorded for recovery in distribution rates. Should be consistent with OPEBs costs as documented in Appendix 2-KA.

# Appendix 2-KA
# OPEBs (Other Post-Employment Benefits) Costs

**A** Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since the distributor started to recover OPEBs in distribution rates from

**Notes:**
(Please add any information to explain the accounting basis used for OPEBs cost recovery in rate setting. If basis is other than Cash or Accrual, an explanation is required.)

Hydro One utilizes the accrual method for accounting of Other Post-Employment Benefit ("OPEBs") costs. The accrual method is appropriate because it reflects the costs incurred during the time period and, as such, more accurately attributes those costs to the appropriate ratepayers.

**B** Please complete the following table:

| OPEBS | First Year of recovery to 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|---|
| **Amounts included in Rates** | | | | | | | | |
| | | $ 774,554 | $ 940,931 | $ 759,957 | $ 865,879 | $ 846,227 | $ 908,769 | $ 5,096,317 |
| OM&A | | $ 249,988 | $ 272,391 | $ 324,924 | $ 346,852 | $ 406,241 | $ 362,546 | $ 1,962,942 |
| Capital | $ - | $ 1,024,542 | $ 1,213,322 | $ 1,084,881 | $ 1,212,731 | $ 1,252,468 | $ 1,271,315 | $ 7,059,259 |
| Total **Paid benefit amounts** | | $ 263,986 | $ 91,388 | $ 51,140 | $ 62,671 | $ 575,553 | $ 604,984 | $ 1,649,722 |
| **Net excess amount included in rates relative to amounts actually paid.** | $ - | $ 760,556 | $ 1,121,934 | $ 1,033,741 | $ 1,150,060 | $ 676,915 | $ 666,331 | $ 5,409,537 |

**C** Please describe what the distributor has done with the recoveries in excess of cash payments:

The Capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net Excess as noted does not represent the excess recovery in each year.

## Appendix 2-M
## Regulatory Cost Schedule

| | Regulatory Cost Category | USoA Account | USoA Account Balance | Ongoing or One-time Cost? [2] | Last Rebasing Year (2013 Board Approved) | 2013 Actuals | 2014 Actuals | 2015 Actuals | Most Current Actuals Year 2016 | 2017 Bridge Year | Annual % Change | 2018 Test Year | Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C ) | (D) | (E) | | | | (F) | (G) | (H) = [(G)-(F)]/(F) | (I) | (J) = [(I)-(G)]/(G) |
| 1 | OEB Annual Assessment | 5655 | | On-Going | $ 86,000 | $ 122,415 | $ 123,723 | $ 130,132 | $ 56,441 | $ 25,000 | -55.71% | $ 25,000 | 0.00% |
| 2 | OEB Section 30 Costs (Applicant-originated) | 5655 | | One-Time | $ 54,000 | $ - | $ 8,872 | | $ - | $ - | | $ 35,000 | |
| 3 | OEB Section 30 Costs (OEB-initiated) | 5655 | | On-Going | | | $ 5,067 | $ 11,449 | $ 11,817 | $ 15,000 | 26.93% | $ 25,000 | 66.67% |
| 4 | Expert Witness costs for regulatory matters | | | | | | | | | | | | |
| 5 | Legal costs for regulatory matters | | | | | | | | | | | | |
| 6 | Consultants' costs for regulatory matters | | | One-Time | | | | | | $ 70,000 | | $ 10,000 | -85.71% |
| 7 | Operating expenses associated with staff resources allocated to regulatory matters | | | | | | | | | | | | |
| 8 | Operating expenses associated with other resources allocated to regulatory matters [1] | | | | | | | | | | | | |
| 9 | Other regulatory agency fees or assessments | | | | | | | | | | | | |
| 10 | Any other costs for regulatory matters: Advertising, Notice | | | One-Time | | $ 11,712 | | | | $ 20,000 | | | -100.00% |
| 11 | Intervenor costs | 5655 | | One-Time | | $ 128,133 | | | | | | $ 80,000 | |
| 12 | Sub-total - Ongoing Costs [3] | | $ - | | $ 86,000 | $ 122,415 | $ 128,790 | $ 141,581 | $ 68,258 | $ 40,000 | -41.40% | $ 50,000 | 25.00% |
| 13 | Sub-total - One-time Costs [4] | | $ - | | $ 54,000 | $ 139,845 | $ 8,872 | $ - | $ - | $ 90,000 | | $ 125,000 | 38.89% |
| 14 | Total | | $ - | | $ 140,000 | $ 262,260 | $ 137,662 | $ 141,581 | $ 68,258 | $ 130,000 | 90.45% | $ 175,000 | 34.62% |

**Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period.**

| | | Historical Year(s) | 2017 Bridge Year | 2018 Test Year |
|---|---|---|---|---|
| 4 | Expert Witness costs | | | |
| 5 | Legal costs | | | |
| 6 | Consultants' costs | | | |
| 7 | Incremental operating expenses associated with staff resources allocated to this application. | | | |
| 8 | Incremental operating expenses associated with other resources allocated to this application. [1] | | | |
| 11 | Intervenor costs | | | |

**Notes:**

1 Please identify the resources involved.
2 Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.
3 Sum of all ongoing costs identified in rows 1 to 11 inclusive.
4 Sum of all one-time costs identified in rows 1 to 11 inclusive.

**HYDRO ONE REMOTE COMMUNITIES INC.**
Depreciation & Amortization Expenses
Historical (2013-2016), Bridge (2017) & Test (2018) Years
Year Ending December 31
(in $K)

| | | Historic | | | | Bridge | Test |
|---|---|---|---|---|---|---|---|
| | | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **Line No.** | **Particulars** | **Provision** | **Provision** | **Provision** | **Provision** | **Provision** | **Provision** |
| | | (b) | (b) | (b) | (b) | (b) | (d) |
| | Depreciation Expenses | | | | | | |
| 1 | Major Fixed Assets | 2,415 | 2,416 | 2,507 | 2,535 | 2,679 | 2,782 |
| 2 | Minor Fixed Assets | 148 | 178 | 204 | 216 | 198 | 160 |
| 3 | Depreciation on Fixed Assets | 2,563 | 2,594 | 2,711 | 2,751 | 2,877 | 2,942 |
| 5 | Asset Removal Costs | 590 | 430 | 969 | 620 | 1,041 | 634 |
| 6 | Losses/(Gains) on Asset Disposition | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Total Depreciation Expenses | **3,153** | **3,024** | **3,680** | **3,371** | **3,918** | **3,576** |
| | Amortization Expenses | | | | | | |
| 8 | Environmental Costs | 1,656 | 1,599 | 1,222 | 1,247 | 1,163 | 1,032 |
| 9 | Total Amortization Expenses | **1,656** | **1,599** | **1,222** | **1,247** | **1,163** | **1,032** |
| 10 | Total Depreciation & Amortization Expenses | **4,809** | **4,623** | **4,902** | **4,618** | **5,081** | **4,608** |

**HYDRO ONE REMOTE COMMUNITIES INC.**
**Depreciation Expense Detail by Asset Class Schedule**

**Year** **2013-2018**

| OEB | Description | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| 1611 | Computer Software (Formally known as Account 1925) | $ - | $ - | $ - | $ - | $ - | |
| 1612 | Land Rights (Formally known as Account 1906) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1615 | Land | $ - | $ - | $ - | $ - | $ - | $ - |
| 1620 | Buildings &Fixtures | -$ 124,399 | -$ 123,387 | -$ 132,687 | 0 | -$ 140,158 | -$ 140,590 |
| 1650 | Reservoirs Dams & Water | $ - | $ - | $ - | $ - | -$ 29,429 | -$ 29,429 |
| 1665 | Fuel Holders Produce | -$ 169,359 | -$ 206,904 | -$ 212,150 | -$ 207,882 | -$ 212,862 | -$ 223,494 |
| 1670 | Prime Movers | -$ 1,120,389 | -$ 1,044,464 | -$ 1,070,467 | -$ 1,079,006 | -$ 1,145,586 | -$ 1,143,573 |
| 1675 | Generators | -$ 388,504 | -$ 411,702 | -$ 421,061 | -$ 420,843 | -$ 402,004 | -$ 443,590 |
| 1680 | Accessory Electc Equ | -$ 145,497 | -$ 142,172 | -$ 150,977 | -$ 150,977 | -$ 158,465 | -$ 180,788 |
| 1685 | Misc Power Plant Equ | -$ 98,641 | -$ 106,123 | -$ 109,075 | -$ 109,075 | -$ 131,722 | -$ 135,336 |
| 1805 | Land | -$ 5,712 | -$ 5,712 | -$ 5,712 | -$ 5,712 | -$ 5,712 | -$ 5,712 |
| 1806 | L&Rights | -$ 2,271 | -$ 2,271 | -$ 2,271 | -$ 2,271 | -$ 2,271 | -$ 2,271 |
| 1808 | Buildings | $ - | $ - | $ - | $ - | $ - | $ - |
| 1810 | Leasehold Improvements | $ - | $ - | $ - | $ - | $ - | $ - |
| 1815 | Transformer Station Equipment >50 kV | $ - | $ - | $ - | $ - | $ - | $ - |
| 1820 | Distribution Station Equipment <50 kV | $ - | $ - | $ - | $ - | $ - | $ - |
| 1825 | Storage Battery Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 1830 | Poles, Towers & Fixtures | -$ 41,705 | -$ 48,533 | -$ 50,610 | -$ 53,920 | -$ 58,452 | -$ 63,120 |
| 1835 | Overhead Conductors & Devices | -$ 31,672 | -$ 34,026 | -$ 37,146 | -$ 42,713 | -$ 45,582 | -$ 49,044 |
| 1840 | Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - |
| 1845 | Underground Conductors & Devices | -$ 5,641 | -$ 7,444 | -$ 7,701 | -$ 7,701 | -$ 7,701 | -$ 7,701 |
| 1850 | Line Transformers | -$ 45,834 | -$ 49,593 | -$ 51,922 | -$ 53,207 | -$ 55,779 | -$ 58,888 |
| 1855 | Services (Overhead & Underground) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1860 | Meters | -$ 45,472 | -$ 35,721 | -$ 38,233 | -$ 41,563 | | -$ 47,046 |
| 1860-A | Meters (Smart Meters) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1905 | Land | $ - | $ - | $ - | $ - | $ - | $ - |
| 1908 | Buildings & Fixtures | -$ 180,309 | -$ 189,482 | -$ 200,421 | -$ 209,500 | -$ 225,375 | -$ 237,386 |
| 1910 | Leasehold Improvements | -$ 7,677 | -$ 7,677 | -$ 15,650 | -$ 12,993 | -$ 12,993 | -$ 12,993 |
| 1955 | Communications Equipment | -$ 687 | -$ 687 | -$ 687 | -$ 687 | -$ 687 | -$ 687 |
| 1955-A | Communication Equipment (Smart Meters) | $ - | $ - | $ - | $ - | $ - | $ - |
| A | Maj Rollup Acc Dep Suspense | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | |
| | **MAJOR FIXED ASSETS** | **-$ 2,413,769** | **-$ 2,415,898** | **-$ 2,506,770** | **-$ 2,535,080** | **-$ 2,678,534** | **-$ 2,781,648** |
| | | | | | | | |
| 1915 | Office Furniture & Equipment (5 years) | -$ 9,389 | -$ 10,004 | -$ 10,775 | -$ 10,775 | -$ 8,998 | -$ 7,646 |
| 1915-A | Office Furniture & Equipment (10 years) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1920 | Computer Equipment - Hardware | -$ 13,625 | -$ 11,849 | -$ 9,497 | -$ 4,083 | -$ 1,238 | $ - |
| 1920-A | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1920-B | Computer Equip.-Hardware(Post Mar. 19/07) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1930 | Transportation Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 1935 | Stores Equipment | -$ 33,246 | -$ 28,971 | -$ 22,325 | -$ 18,844 | -$ 17,859 | -$ 16,838 |
| 1940 | Tools, Shop & Garage Equipment | -$ 8,359 | -$ 12,360 | -$ 14,446 | -$ 17,337 | -$ 17,544 | -$ 14,625 |
| 1945 | Measurement & Testing Equipment | -$ 16,449 | -$ 23,619 | -$ 25,189 | -$ 23,962 | -$ 21,634 | -$ 14,917 |
| 1950 | Power Operated Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 1960 | Miscellaneous Equipment | -$ 68,658 | -$ 91,350 | -$ 122,464 | -$ 141,025 | -$ 131,056 | -$ 105,872 |
| 1975 | Load Management Controls Utility Premises | $ - | $ - | $ - | $ - | $ - | $ - |
| 1980 | System Supervisor Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 1985 | Miscellaneous Fixed Assets | $ - | $ - | $ - | $ - | $ - | $ - |
| 1995 | Contributions & Grants | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | |
| | **MINOR FIXED ASSETS** | **-$ 149,726** | **-$ 178,153** | **-$ 204,696** | **-$ 216,026** | **-$ 198,329** | **-$ 159,898** |
| | | | | | | | |
| | **Total Depreciation on Fixed Assets** | **-$ 2,563,495** | **-$ 2,594,051** | **-$ 2,711,466** | **-$ 2,751,106** | **-$ 2,876,863** | **-$ 2,941,546** |

# HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Utility Income Taxes
Test Year (2018)
Year Ending December 31
(in $K)

| Line No. | Particulars | | 2018 | |
|---|---|---|---|---|
| | **Determination of Taxable Income** | | | |
| 1 | Regulatory Net Income (before tax) | $ | (0) | |
| 2 | Book to Tax Adjustments: | | | |
| 3 | Other Post Employment Benefits expense | | 910 | |
| 4 | Other Post Employment Benefits payments | | (605) | |
| 5 | Depreciation and amortization | | 4,607 | |
| 6 | Capital Cost Allowance | | (3,026) | * |
| 7 | Removal costs | | (164) | |
| 8 | Environmental costs | | (1,032) | |
| 9 | Non-deductible meals & entertainment | | 44 | |
| 10 | Capitalized interest deduction | | (117) | |
| 11 | Capitalized overhead costs deduction | | (443) | |
| 12 | Capitalized pension costs deduction | | (437) | |
| 13 | | $ | (262) | |
| 14 | | | | |
| 15 | Regulatory Taxable Income | $ | (262) | |
| 16 | | | | |
| 17 | | | | |
| 18 | Calculation of Utility Income Taxes | | | |
| 19 | | | | |
| 20 | Corporate Income Tax Rate | | 26.50 | % |
| 21 | | | | |
| 22 | Regulatory Income Tax | $ | (69) | |
| 23 | | | | |
| 24 | | | | |
| 25 | Income Tax Rates: | | | |
| 26 | | | | |
| 27 | Federal Tax | | 15.00 | % |
| 28 | Provincial Tax | | 11.50 | % |
| 29 | Total Federal and ON Tax rate | | 26.50 | % |

* Excludes CCA related on revaluation of assets due to IPO

# HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Capital Cost allowance (CCA)
Test and Bridge Year
2017 & 2018
Year Ending December 31
(in $K)

**2017**

| CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|
| 1 | 17,001 | 832 | 17,833 | 416 | 17,417 | 4% | 697 | 17,136 |
| 2 | 409 | - | 409 | - | 409 | 6% | 25 | 384 |
| 3 | 606 | - | 606 | - | 606 | 5% | 30 | 575 |
| 6 | 4,274 | - | 4,274 | - | 4,274 | 10% | 427 | 3,847 |
| 8 | 858 | 166 | 1,024 | 83 | 941 | 20% | 188 | 836 |
| 10 | 131 | - | 131 | - | 131 | 30% | 39 | 92 |
| 12 | 0 | - | 0 | - | 0 | 100% | 0 | - |
| 13 | 86 | - | 86 | - | 86 | SL | 17 | 69 |
| 17 | 14,665 | 1,032 | 15,697 | 516 | 15,181 | 8% | 1,214 | 14,482 |
| 42 | 115 | - | 115 | - | 115 | 12% | 14 | 102 |
| 43.1 | 429 | - | 429 | - | 429 | 30% | 129 | 301 |
| 45 | 0 | - | 0 | - | 0 | 45% | 0 | 0 |
| 47 | 3,751 | 776 | 4,527 | 388 | 4,139 | 8% | 331 | 4,196 |
| 50 | 0 | 9 | 9 | 5 | 5 | 55% | 3 | 7 |
| **CCA** | **42,326** | **2,815** | **45,140** | **1,407** | **43,733** | | **3,114** | **42,026** |

**2018**

| CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|
| 1 | 17,136 | 423 | 17,559 | 212 | 17,348 | 4% | 694 | 16,866 |
| 2 | 384 | - | 384 | - | 384 | 6% | 23 | 361 |
| 3 | 575 | - | 575 | - | 575 | 5% | 29 | 546 |
| 6 | 3,847 | - | 3,847 | - | 3,847 | 10% | 385 | 3,462 |
| 8 | 836 | 166 | 1,002 | 83 | 919 | 20% | 184 | 818 |
| 10 | 92 | - | 92 | - | 92 | 30% | 27 | 64 |
| 12 | - | - | - | - | - | 100% | - | - |
| 13 | 69 | - | 69 | - | 69 | SL | 14 | 55 |
| 17 | 14,482 | 1,196 | 15,678 | 598 | 15,080 | 8% | 1,206 | 14,472 |
| 42 | 102 | - | 102 | - | 102 | 12% | 12 | 89 |
| 43.1 | 301 | - | 301 | - | 301 | 30% | 90 | 210 |
| 45 | 0 | - | 0 | - | 0 | 45% | 0 | 0 |
| 47 | 4,196 | 513 | 4,709 | 257 | 4,453 | 8% | 356 | 4,353 |
| 50 | 7 | 9 | 16 | 5 | 11 | 55% | 6 | 9 |
| **CCA** | **42,026** | **2,307** | **44,333** | **1,154** | **43,179** | | **3,026** | **41,307** |

**HYDRO ONE REMOTE COMMUNITIES INC.**

Calculation of Utility Income Taxes
Historic Years
2013-2016
Year Ending December 31
(in $K)

The following only includes tax adjustments relate to the Remotes regulated operations only. Any tax adjustments relating to non-regulated activities (i.e. IPO) have not been included.

| Line | Particulars | | 2013 | | 2014 | | 2015 | | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| | **Calculation of Federal and ON Taxable Income** | | | | | | | | |
| 1 | Net Income Before Tax (NIBT) | $ | (1,091) | $ | 10 | $ | 628 | $ | 461 |
| 2 | **Required Adjustments to accounting NIBT** | | | | | | - | | |
| 3 | **Recurring items included in Revenue Requirement (RR):** | | | | | | - | | |
| 4 | Post Employment Benefit accrual in excess of payments | | 514 | | 850 | | 755 | | 803 |
| 5 | Depreciation and amortization | | 4,809 | | 4,623 | | 4,902 | | 4,618 |
| 6 | Capital Cost Allowance | | (2,826) | | (3,272) | | (3,192) | | (3,183) |
| 7 | Removal costs | | (213) | | (86) | | (133) | | (87) |
| 8 | Environmental costs deduction | | (1,656) | | (1,599) | | (1,222) | | (1,247) |
| 9 | Non-deductible M & E / interest | | 32 | | 80 | | 21 | | 19 |
| 10 | Capitalized overhead costs deducted | | (309) | | (349) | | (541) | | (392) |
| 11 | Capitalized Pension costs deducted | | (338) | | (347) | | (477) | | (287) |
| 12 | Losses utized in rates | | - | | - | | - | | - |
| 13 | Loss Carryforwards utilized | $ | - | | 2,859 | | (3,285) | | - |
| 14 | | | 13 | $ | 2,759 | $ | (3,171) | $ | 244 |
| 15 | **Deferral accounts not part of RR:** | | | | | | | | |
| 16 | RRRP | | (1,199) | | (2,593) | | 1,819 | | 1,116 |
| 17 | | $ | (1,199) | $ | (2,593) | $ | 1,819 | $ | 1,116 |
| 18 | **Reversal of accounting adjustments not part of RR:** | | | | | | | | |
| 19 | Capitalized interest deductible for tax | | (376) | | (146) | | (97) | | (115) |
| 20 | | $ | (376) | $ | (146) | $ | (97) | $ | (115) |
| 21 | **Recurring items not part of RR:** | | | | | | | | |
| 22 | | | | | | | | | |
| 23 | **Immaterial items not in business plan detail:** | | | | | | | | |
| 24 | Capital items deducted for accounting | | 1 | | 3 | | 13 | | 2 |
| 25 | Interest deduction net of financing costs amortized | | 16 | | 6 | | 7 | | 3 |
| 26 | Regulatory Asset Movement | | 73 | | - | | - | | - |
| 27 | Additional CCA due to IPO | | - | | - | | - | | - |
| 28 | Losses utilized/(carryforward) from IPO | | | | | | - | | - |
| 29 | Other | | 39 | | (39) | | (108) | | 62 |
| 30 | | | 129 | | (30) | | (88) | | 67 |
| 31 | | | | | | | | | |
| 32 | NET Adjustments to Accounting NIBT | $ | (1,434) | $ | (10) | $ | (1,538) | $ | 1,312 |
| 33 | Prior years Non capital loss C/F utilized | | | | | | | | |
| 34 | Taxable Income Federal and Ontario | $ | (2,525) * | $ | 0 | $ | (910) | $ | 1,773 |
| 35 | | | | | | | | | |
| 36 | **Income Tax:** | | | | | | | | |
| 37 | Federal Income Tax | | (379) | | 0 | | (137) | | 266 |
| 38 | ON Income Tax | | (290) | | 0 | | (105) | | 204 |
| 39 | Total Income Tax Per Returns | | (669) | | - | | (241) | | 470 |
| 40 | | | | | | | | | |
| 41 | Tax Credits | | (31) | | (56) | | (59) | | (29) |
| 42 | Tax Payable/(Recovery) net of tax credits | | (700) | | (56) | | (301) | | 440 |
| 43 | | | | | | | | | |
| 44 | Federal Tax | | 15.0% | | 15.0% | | 15.0% | | 15.0% |
| 45 | Provincial Tax | | 11.5% | | 11.5% | | 11.5% | | 11.5% |
| 46 | Corporate Income Tax Rate | | 26.5% | | 26.5% | | 26.5% | | 26.5% |
| 47 | | | | | | | | | |
| 48 | * Losses were carried back to offset taxable income. | | | | | | | | |

# HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Capital Cost allowance (CCA)
Historic Years
2013-2016
Year Ending December 31
(in $K)

| **2013** CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Closing UCC | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 17,530 | 526 | 18,055 | 263 | 17,792 | 4% | 712 | 17,344 | |
| 2 | 523 | - | 523 | - | 523 | 6% | 31 | 492 | |
| 3 | 743 | - | 743 | - | 743 | 5% | 37 | 706 | |
| 6 | 2,799 | 2,068 | 4,867 | 1,034 | 3,833 | 10% | 383 | 4,484 | |
| 8 | 868 | 215 | 1,083 | 108 | 975 | 20% | 195 | 888 | |
| 10 | 373 | 35 | 408 | 18 | 391 | 30% | 117 | 291 | |
| 12 | 3 | 0 | 3 | 0 | 3 | 100% | 3 | 0 | |
| 13 | 61 | - | 61 | - | 61 | N/A | 4 | 57 | |
| 17 | 9,888 | 4,255 | 14,143 | 2,127 | 12,015 | 8% | 961 | 13,182 | |
| 42 | 192 | - | 192 | - | 192 | 12% | 23 | 169 | |
| 43.1 | 1 | 982 | 983 | 491 | 492 | 30% | 147 | 835 | |
| 45 | 1 | - | 1 | - | 1 | 45% | 1 | 1 | |
| 47 | 2,512 | 224 | 2,736 | 112 | 2,624 | 8% | 210 | 2,526 | |
| 50 | 3 | - | 3 | - | 3 | 55% | 2 | 1 | |
| **CCA** | **35,496** | **8,305** | **43,801** | **4,153** | **39,649** | | **2,826** | **40,975** | - |

| **2014** CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Closing UCC | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 17,344 | 307 | 17,651 | 154 | 17,497 | 4% | 700 | 16,951 | |
| 2 | 492 | - | 492 | - | 492 | 6% | 30 | 463 | |
| 3 | 706 | - | 706 | - | 706 | 5% | 35 | 671 | |
| 6 | 4,484 | 1,296 | 5,780 | 648 | 5,132 | 10% | 513 | 5,267 | |
| 8 | 888 | 188 | 1,076 | 94 | 982 | 20% | 196 | 880 | |
| 10 | 291 | 63 | 354 | 32 | 322 | 30% | 97 | 257 | |
| 12 | 0 | 2 | 2 | 1 | 1 | 100% | 1 | 1 | |
| 13 | 57 | 47 | 105 | 24 | 81 | N/A | 8 | 97 | |
| 17 | 13,182 | 2,471 | 15,653 | 1,236 | 14,417 | 8% | 1,153 | 14,500 | |
| 42 | 169 | - | 169 | - | 169 | 12% | 20 | 149 | |
| 43.1 | 835 | 324 | 1,159 | 162 | 997 | 30% | 299 | 860 | |
| 45 | 1 | - | 1 | - | 1 | 45% | 0 | 0 | |
| 47 | 2,526 | 413 | 2,939 | 207 | 2,733 | 8% | 219 | 2,721 | |
| 50 | 1 | - | 1 | - | 1 | 55% | 1 | 1 | |
| **CCA** | **40,975** | **5,112** | **46,087** | **2,556** | **43,531** | | **3,272** | **42,815** | - |

| **2015** CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Closing UCC | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 16,951 | 564 | 17,515 | 282 | 17,233 | 4% | 683 | 16,831 | |
| 2 | 463 | - | 463 | - | 463 | 6% | 27 | 435 | |
| 3 | 671 | - | 671 | - | 671 | 5% | 33 | 637 | |
| 6 | 5,267 | - | 5,267 | - | 5,267 | 10% | 518 | 4,749 | |
| 8 | 880 | 287 | 1,167 | 144 | 1,023 | 20% | 202 | 965 | |
| 10 | 257 | 3 | 261 | 2 | 259 | 30% | 74 | 187 | |
| 12 | 1 | 2 | 3 | 1 | 2 | 100% | 1 | 1 | |
| 13 | 97 | - | 97 | - | 97 | N/A | 4 | 93 | |
| 17 | 14,500 | 578 | 15,078 | 289 | 14,789 | 8% | 1,163 | 13,914 | |
| 42 | 149 | - | 149 | - | 149 | 12% | 17 | 131 | |
| 43.1 | 860 | 0 | 860 | 0 | 860 | 30% | 246 | 613 | |
| 45 | 0 | - | 0 | - | 0 | 45% | 0 | 0 | |
| 47 | 2,721 | 992 | 3,713 | 496 | 3,217 | 8% | 225 | 3,488 | |
| 50 | 1 | - | 1 | - | 1 | 55% | 0 | 0 | |
| **CCA** | **42,815** | **2,427** | **45,242** | **1,213** | **44,028** | | **3,195** | **42,047** | - |

| **2016** CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Closing UCC | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 16,831 | 860 | 17,692 | 430 | 17,262 | 4% | 690 | 17,001 | |
| 2 | 435 | - | 435 | - | 435 | 6% | 26 | 409 | |
| 3 | 637 | - | 637 | - | 637 | 5% | 32 | 606 | |
| 6 | 4,749 | - | 4,749 | - | 4,749 | 10% | 475 | 4,274 | |
| 8 | 965 | 95 | 1,060 | 48 | 1,013 | 20% | 203 | 858 | |
| 10 | 187 | - | 187 | - | 187 | 30% | 56 | 131 | |
| 12 | 1 | 0 | 2 | 0 | 1 | 100% | 1 | 0 | |
| 13 | 93 | - | 93 | - | 93 | N/A | 7 | 86 | |
| 17 | 13,914 | 1,941 | 15,856 | 971 | 14,885 | 8% | 1,191 | 14,665 | |
| 42 | 131 | - | 131 | - | 131 | 12% | 16 | 115 | |
| 43.1 | 613 | - | 613 | - | 613 | 30% | 184 | 429 | |
| 45 | 0 | - | 0 | - | 0 | 45% | 0 | 0 | |
| 47 | 3,488 | 565 | 4,053 | 282 | 3,771 | 8% | 302 | 3,751 | |
| 50 | 0 | - | 0 | - | 0 | 55% | 0 | 0 | |
| **CCA** | **42,047** | **3,462** | **45,509** | **1,731** | **43,778** | | **3,183** | **42,326** | - |

# HYDRO ONE REMOTE COMMUNITIES INC.

## INCOME TAX RETURNS

Attachment 1: Hydro One Remote Communities Inc. Income Tax Return 2013

Attachment 2: Hydro One Remote Communities Inc. Income Tax Return 2014

Attachment 3: Hydro One Remote Communities Inc. Income Tax Return October 31, 2015

Attachment 4: Hydro One Remote Communities Inc. Income Tax Return November 4, 2015

Attachment 5: Hydro One Remote Communities Inc. Income Tax Return December 31, 2015

Attachment 6: Hydro One Remote Communities Inc. Income Tax Return 2016

200

Canada Revenue Agency / Agence du revenu du Canada

# T2 Corporation Income Tax Return

055 Do not use this area

Filed: 2017-08-28
EB-2017-0051
Exhibit D2-09-01
Attachment 1
Page 1 of 87

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

## Identification

**Business number (BN)** . . . . . . . . . . 001 87083 6269 RC0001

**Corporation's name**
002 Hydro One Remote Communities Inc.

**Address of head office**
Has this address changed since the last time we were notified? . . . . . . . . . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 483 Bay Street 8th Floor
012 South Tower
City: 015 Toronto
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 M5G 2P5

**Mailing address** (if different from head office address)
Has this address changed since the last time we were notified? . . . . . . . . . . . 020 1 Yes [X] 2 No [ ]
(If **yes**, complete lines 021 to 028.)
021 c/o Selma Yam
022 483 Bay Street 7th Floor
023 South Tower
City: 025 Toronto
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal code/Zip code: 028 M5G 2P5

**Location of books and records**
Has the location of books and records changed since the last time we were notified? . . . . . . . . . . . . . . . . . . . . . 030 1 Yes [X] 2 No [ ]
(If **yes**, complete lines 031 to 038.)
031 483 Bay Street 7th Floor
032 South Tower
City: 035 Toronto
Province,territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 M5G 2P5

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . . . . . . . . . . . 043 ________ YYYY MM DD

**To which tax year does this return apply?**
Tax year start 060 2013-01-01 (YYYY MM DD)
Tax year-end 061 2013-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . . . . . 063 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired . . . . . . . . . . . . . . 065 ________ YYYY MM DD

**Is the date on line 061 a deemed tax year-end according to:**
subparagraph 88(2)(a)(iv)? . . . . . . . . 064 1 Yes [ ] 2 No [X]
subsection 249(3.1)? . . . . . . . . . . . . 066 1 Yes [ ] 2 No [X]

**Is the corporation a professional corporation that is a member of a partnership?** . . . . . . . . . . . . . . . . 067 1 Yes [ ] 2 No [X]

**Is this the first year of filing after:**
Incorporation? . . . . . . . . . . . . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . . . . . . . . . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . 076 1 Yes [ ] 2 No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . . 078 1 Yes [ ] 2 No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . 079 ________

**Is the corporation a resident of Canada?**
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ________

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

**Do not use this area**
095 ________ 096 ________

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| Is the corporation an associated CCPC? | 160 | X | 23 |
| Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders who own voting shares? | 151 | | 19 |
| Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | X | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | X | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership account number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation have any foreign affiliates during the year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*? | 170 | | 29 |
| Has the corporation had any non-arm's length transactions with a non-resident? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | X | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine? | 202 | | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | | 3 |
| Is the corporation claiming any type of losses? | 204 | X | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | X | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | | 6 |
| i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440? | 207 | | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any property that is eligible capital property? | 210 | | 10 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)? | 213 | | 13 |
| Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits? | 221 | | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | | 31 |
| Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | | |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | | |
| Is the corporation claiming a surtax credit? | 237 | | 37 |
| Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II - Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit refund? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit refund? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments – continued from page 2

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates that are not controlled foreign affiliates? | 256 | | T1134 |
| Did the corporation have any controlled foreign affiliates? | 258 | | T1134 |
| Did the corporation own specified foreign property in the year with a cost amount over $100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | 262 | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | X | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | | X |
| Is the corporation inactive? | 280 | | X |

What is the corporation's main revenue-generating business activity? ..... 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

| Line | Product/service | Line | % |
|---|---|---|---|
| 284 | Electricity generation and distribution | 285 | 100.000 % |
| 286 | | 287 | % |
| 288 | | 289 | % |

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | | X |
| Did the corporation emigrate from Canada during the tax year? | 292 | | X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | | X |

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible ..... 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? ..... 295 1 Yes [ ] 2 No [ ]

## Taxable income

| | Line | Amount | | Total | |
|---|---|---|---|---|---|
| Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. | 300 | | | -2,524,507 | A |
| **Deduct:** Charitable donations from Schedule 2 | 311 | | | | |
| Gifts to Canada, a province, or a territory from Schedule 2 | 312 | | | | |
| Cultural gifts from Schedule 2 | 313 | | | | |
| Ecological gifts from Schedule 2 | 314 | | | | |
| Gifts of medicine from Schedule 2 | 315 | | | | |
| Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | | | | |
| Part VI.1 tax deduction* | 325 | | | | |
| Non-capital losses of previous tax years from Schedule 4 | 331 | | | | |
| Net capital losses of previous tax years from Schedule 4 | 332 | | | | |
| Restricted farm losses of previous tax years from Schedule 4 | 333 | | | | |
| Farm losses of previous tax years from Schedule 4 | 334 | | | | |
| Limited partnership losses of previous tax years from Schedule 4 | 335 | | | | |
| Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | | |
| Prospector's and grubstaker's shares | 350 | | | | |
| Subtotal | | | ► | | B |
| Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | | | C |
| **Add:** Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | 355 | | | | D |
| **Taxable income** (amount C **plus** amount D) | 360 | | | | |
| Income exempt under paragraph 149(1)(t) | 370 | | | | |
| **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | | | Z |

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

Income from active business carried on in Canada from Schedule 7 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **410** ______ C

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction:**

Amount C ______ x **415** ***** ______ D = . . . . . . . . . . . . . . . . . . . . . . . . ______ E
11,250

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . **425** ______ F

**Small business deduction**

Amount A, B, C, or F, whichever is the least ______ x 17 % = . . . . . . . . . . . . . . . . . . . . . . . . **430** ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

Taxable income from line 360 on page 3* ........ A

Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 ........ B

Amount QQ from Part 13 of Schedule 27 ........ C

Personal service business income** ........ 432 ........ D

Amount used to calculate the credit union deduction (amount F from Schedule 17) ........ E

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least ........ F

Aggregate investment income from line 440 on page 6*** ........ G

Total of amounts B to G ........ ▶ ........ H

Amount A **minus** amount H (if negative, enter "0") ........ I

Amount I ______ x (Number of days in the tax year after December 31, 2010, and before January 1, 2012 ______ / Number of days in the tax year 365) x 11.5 % = ______ J

Amount I ______ x (Number of days in the tax year after December 31, 2011 365 / Number of days in the tax year 365) x 13 % = ______ K

**General tax reduction for Canadian-controlled private corporations** – Amount J **plus** amount K ........ L

Enter amount L on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

Taxable income from page 3 (line 360 or amount Z, whichever applies) ........ M

Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 ........ N

Amount QQ from Part 13 of Schedule 27 ........ O

Personal service business income* ........ 434 ........ P

Amount used to calculate the credit union deduction (amount F from Schedule 17) ........ Q

Total of amounts N to Q ........ ▶ ........ R

Amount M **minus** amount R (if negative, enter "0") ........ S

Amount S ______ x (Number of days in the tax year after December 31, 2010, and before January 1, 2012 ______ / Number of days in the tax year 365) x 11.5 % = ______ T

Amount S ______ x (Number of days in the tax year after December 31, 2011 365 / Number of days in the tax year 365) x 13 % = ______ U

**General tax reduction** – Amount T **plus** amount U ........ V

Enter amount V on line 639 on page 7.

* For tax years beginning after October 31, 2011.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

Aggregate investment income from Schedule 7 . . . . . . . . **440** ______ x 26 2 / 3 % = . . . . . . . . . . . . . . . . ______ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . . . . . . . . . . . . . . . . . . ______ B

**Deduct:**
Foreign investment income from Schedule 7 . . . . . . . . . . . **445** ______ x 9 1 / 3 % = ______ C
(if negative, enter "0") ______ ▶ ______ D

Amount A **minus** amount D (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ E

Taxable income from line 360 on page 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ F

**Deduct:**
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ G

Foreign non-business income tax credit from line 632 on page 7 . . . ______ x 25/9* 100 / 35 = ______ H

Foreign business income tax credit from line 636 on page 7 . . . . . . . . . . . . . ______ x 1(0.38 - X**) 4 = ______ I

Subtotal ______ ▶ ______ J

______ K

x 26 2 / 3 % = ______ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . . . . . . . . . . . . . . . . . . . . ______ M

**Refundable portion of Part I tax** – Amount E, L, or M, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **450** ______ N

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

## Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . . . . . . . . . . . . . . **460** ______

**Deduct:** Dividend refund for the previous tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **465** ______

______ ▶ ______ O

**Add** the total of:

Refundable portion of Part I tax from line 450 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ P

Total Part IV tax payable from Schedule 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . . . . . . . . . . . . . . . . . . . **480** ______

______ ▶ ______ R

**Refundable dividend tax on hand at the end of the tax year** – Amount O **plus** amount R . . . . . . . . . . . . . . . . . . . . . **485** ______

## Dividend refund

**Private and subject corporations at the time taxable dividends were paid in the tax year**

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . . . . . . ______ x 1 / 3 = ______ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . . . . . . . . . . . . . . . . . . . . . ______ T

**Dividend refund** – Amount S or T, whichever is less (enter this amount on line 784 on page 8) . . . . . . . . . . . . . . . . . . . . ______

## Part I tax

**Base amount of Part I tax** – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % 550 ______ A

**Recapture of investment tax credit from Schedule 31** . . . . . 602 ______ B

**Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income**
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . . ______ i

Taxable income from line 360 on page 3 . . . . . ______

**Deduct:**

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . ______

Net amount . . . . . ______ ▶ ______ ii

**Refundable tax on CCPC's investment income** – 6 2 / 3 % of whichever is less: amount i or ii . . . . . 604 ______ C

Subtotal (**add** amounts A to C) ______ D

**Deduct:**

Small business deduction from line 430 on page 4 . . . . . ______ 1

Federal tax abatement . . . . . 608 ______

Manufacturing and processing profits deduction from Schedule 27 . . . . . 616 ______

Investment corporation deduction . . . . . 620 ______

Taxed capital gains 624 ______

Additional deduction – credit unions from Schedule 17 . . . . . 628 ______

Federal foreign non-business income tax credit from Schedule 21 . . . . . 632 ______

Federal foreign business income tax credit from Schedule 21 . . . . . 636 ______

General tax reduction for CCPCs from amount L on page 5 . . . . . 638 ______

General tax reduction from amount V on page 5 . . . . . 639 ______

Federal logging tax credit from Schedule 21 . . . . . 640 ______

Federal qualifying environmental trust tax credit . . . . . 648 ______

Investment tax credit from Schedule 31 . . . . . 652 ______

Subtotal ______ ▶ ______ E

**Part I tax payable** – Amount D **minus** amount E . . . . . ______ F

Enter amount F on line 700 on page 8.

## Summary of tax and credits

**Federal tax**

| | | |
|---|---|---|
| Part I tax payable from page 7 | 700 | |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | | |
|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | |
| Provincial tax on large corporations (Nova Scotia Schedule 342) | 765 | |
| (The Nova Scotia tax on large corporations is eliminated effective July 1, 2012.) Total provincial tax | | |

Total tax payable 770 ______ A

**Deduct other credits:**

| | | | |
|---|---|---|---|
| Investment tax credit refund from Schedule 31 | 780 | | |
| Dividend refund from page 6 | 784 | | |
| Federal capital gains refund from Schedule 18 | 788 | | |
| Federal qualifying environmental trust tax credit refund | 792 | | |
| Canadian film or video production tax credit refund (Form T1131) | 796 | | |
| Film or video production services tax credit refund (Form T1177) | 797 | | |
| Tax withheld at source | 800 | | |
| Total payments on which tax has been withheld | 801 | | |
| Provincial and territorial capital gains refund from Schedule 18 | 808 | | |
| Provincial and territorial refundable tax credits from Schedule 5 | 812 | 30,604 | |
| Tax instalments paid | 840 | | |
| Total credits | 890 | 30,604 | 30,604 B |

Refund code 894 ______ Overpayment 30,604

Balance (amount A **minus** amount B) -30,604

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . . . . ______

Enclosed payment 898 ______

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920 ______

## Certification

I, 950 BARAGETTI (Last name (print)) 951 GIOVANNA (First name (print)) 954 Vice President, Corporate Tax (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 June 25/14 (Date (yyyy/mm/dd)) ______ Signature of the authorized signing officer of the corporation 956 (416) 345-6778 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No ☒

958 SELMA YAM (Name (print)) 959 (416) 345-6827 Telephone number

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

*Privacy Act*, Personal Information Bank number CRA PPU 047

# HYDRO ONE REMOTE COMMUNITIES INC.

## FINANCIAL STATEMENTS

## DECEMBER 31, 2013

**HYDRO ONE REMOTE COMMUNITIES INC.**
**INDEPENDENT AUDITORS' REPORT**

To Directors of Hydro One Remote Communities Inc.

We have audited the accompanying financial statements of Hydro One Remote Communities Inc., which comprise the balance sheet as at December 31, 2013, the statements of operations and comprehensive income, changes in shareholder's deficit and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these 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 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 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 Hydro One Remote Communities Inc. as at December 31, 2013, and its results of operations and its cash flows for the year then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 26, 2014

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
**For the years ended December 31, 2013 and 2012**

| *Year ended December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| **Revenues** *(Note 15)* | 50,035 | 46,766 |
| **Costs** | | |
| Operation, maintenance and administration *(Note 15)* | 19,645 | 16,861 |
| Fuel used for electric generation | 25,568 | 24,306 |
| Depreciation and amortization *(Note 4)* | 4,809 | 6,019 |
| | 50,022 | 47,186 |
| **Income (loss) before financing charges and recovery of payments in lieu of corporate income taxes** | 13 | (420) |
| Financing charges *(Notes 5, 15)* | 1,104 | 1,016 |
| **Loss before recovery of payments in lieu of corporate income taxes** | (1,091) | (1,436) |
| Recovery of payments in lieu of corporate income taxes *(Notes 6, 15)* | (1,091) | (1,436) |
| **Net income** | – | – |
| Other comprehensive income | 13 | 12 |
| **Comprehensive income** | 13 | 12 |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS**
**At December 31, 2013 and 2012**

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Accounts receivable (net of allowance for doubtful accounts – \$296; 2012 – \$297) *(Notes 7, 15)* | 4,995 | 4,193 |
| Regulatory assets *(Note 9)* | 2,427 | 1,823 |
| Fuel, materials and supplies | 1,736 | 2,179 |
| Deferred income tax assets *(Note 6)* | 108 | 108 |
| Income tax receivable *(Notes 6, 15)* | 2,697 | 1,589 |
| | 11,963 | 9,892 |
| Property, plant and equipment *(Note 8)*: | | |
| Property, plant and equipment in service | 58,905 | 54,790 |
| Less: accumulated depreciation | 23,256 | 25,779 |
| | 35,649 | 29,011 |
| Construction in progress | 3,473 | 7,250 |
| Future use components and spares | 1,650 | 1,573 |
| | 40,772 | 37,834 |
| Other long-term assets: | | |
| Regulatory assets *(Note 9)* | 15,923 | 14,060 |
| Deferred income tax assets *(Note 6)* | 4,239 | 4,733 |
| Deferred debt costs *(Note 10)* | 124 | 128 |
| Long-term accounts receivable (net of allowance for doubtful accounts – \$0; 2012 – \$5) *(Note 7)* | 674 | 418 |
| | 20,960 | 19,339 |
| **Total assets** | 73,695 | 67,065 |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS (continued)**
**At December 31, 2013 and 2012**

| *December 31 (thousands of dollars ,except number of shares)* | **2013** | **2012** |
|---|---|---|
| **Liabilities** | | |
| Current liabilities: | | |
| Inter-company demand facility *(Notes 11, 15)* | 18,031 | 11,212 |
| Accounts payable | 703 | 987 |
| Accrued liabilities *(Notes 12, 13)* | 4,954 | 5,876 |
| Accrued interest *(Note 15)* | 142 | 142 |
| Regulatory liabilities *(Note 9)* | 109 | 108 |
| | 23,939 | 18,325 |
| Long-term debt *(Notes 10, 11, 15)* | 23,000 | 23,000 |
| Other long-term liabilities: | | |
| Post-retirement and post-employment benefit liability *(Note 12)* | 12,088 | 11,532 |
| Regulatory liabilities *(Note 9)* | 4,238 | 4,733 |
| Environmental liabilities *(Note 13)* | 10,999 | 10,057 |
| | 27,325 | 26,322 |
| **Total liabilities** | 74,264 | 67,647 |
| *Contingencies and commitments (Notes 17, 18)* | | |
| **Shareholder's deficit** | | |
| Common shares (authorized: unlimited; issued: 2) *(Note 14)* | – | – |
| Accumulated other comprehensive loss | (569) | (582) |
| **Total shareholder's deficit** | (569) | (582) |
| **Total liabilities and shareholder's deficit** | 73,695 | 67,065 |

*See accompanying notes to Financial Statements.*

On behalf of the Board of Directors:

Carmine Marcello
Chair

Lee Ann Cameron
Director

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CHANGES IN SHAREHOLDER'S DEFICIT**
**For the years ended December 31, 2013 and 2012**

| *Year ended December 31, 2013* *(thousands of dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2013 | – | (582) | (582) |
| Other comprehensive income | – | 13 | 13 |
| **December 31, 2013** | – | (569) | (569) |

| *Year ended December 31, 2012* *(thousands of dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2012 | – | (594) | (594) |
| Other comprehensive income | – | 12 | 12 |
| **December 31, 2012** | – | (582) | (582) |

*See accompanying notes to Financial Statements.*

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CASH FLOWS
**For the years ended December 31, 2013 and 2012**

| *Year ended December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| **Operating activities** | | |
| Net income | – | – |
| Environmental expenditures | (1,656) | (2,515) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (excluding removal costs) | 4,220 | 5,461 |
| Regulatory assets and liabilities | (1,126) | (3,957) |
| Amortization of hedging losses | 13 | 12 |
| Amortization of deferred debt costs and debt discounts | 3 | 2 |
| Gain on disposition of property, plant and equipment | – | (2) |
| Changes in non-cash balances related to operations *(Note 16)* | (2,773) | (947) |
| **Net cash used in operating activities** | (1,319) | (1,946) |
| **Investing activities** | | |
| Capital expenditures | (5,427) | (7,042) |
| Proceeds on disposition of property, plant and equipment | 4 | 11 |
| Future use assets | (77) | (23) |
| **Net cash used in investing activities** | (5,500) | (7,054) |
| **Net change in inter-company demand facility** | (6,819) | (9,000) |
| Inter-company demand facility, beginning of year | (11,212) | (2,212) |
| **Inter-company demand facility, end of year** | (18,031) | (11,212) |

*See accompanying notes to Financial Statements.*

HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS
**For the years ended December 31, 2013 and 2012**

## 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 Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario), and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The Company uses a cost recovery model applied to achieve breakeven net income and are for the specific use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2013 have been prepared and are publicly available.

Hydro One Remote Communities 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. No such events or transactions were identified.

### Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairment, contingencies, unbilled revenue, allowance for doubtful accounts 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

On April 3, 2012, the OEB approved the Company's request to use US GAAP as the basis for rate setting and regulatory accounting and reporting, effective January 1, 2012.

In November 2011, Hydro One Remote Communities filed an Incentive Regulation Mechanism (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 for 2013 distribution rates. The application requested an increase of 3.45% to customer rates for generation and distribution and an increase of approximately $7 million to annual Rural and Remote Rate Protection (RRRP). In September, 2013, the OEB approved the proposed rate increase and annual RRRP of approximately $32.3 million.

**Regulatory Accounting**

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

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of the recovery of / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in RRRP amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

**Revenue Recognition**

Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues attributable to the generation and 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 RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

**Accounts Receivable and Allowance for Doubtful Accounts**

Billed accounts receivable are recorded at the invoiced amount and overdue amounts related to regulated billings bear interest at OEB approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 120 days from the bill due 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 Remote Communities is required to make (recover) PILs to (from) 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 Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

*Current Income Taxes*

The recovery of or 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 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.

**Inter-company Demand Facility**

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash 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%.

**Fuel, Materials and Supplies**

Fuel is used in the generation of electricity. 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

*Generation*

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

*Distribution*

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

*Administration and Service*

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

**Capitalized Financing Costs**

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 in Progress**

Construction 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**

The cost of property, plant and equipment is depreciated 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 depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 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 |
|---|---|---|---|
| Generation | 22 years | 3% – 7% | 5% |
| Distribution | 36 years | 1% – 7% | 3% |
| Administration and service | 20 years | 3% – 20% | 3% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 assets where no asset retirement obligation 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 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. 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 the 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 rate 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents OCI and net income 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.

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 11 – Fair Value of Financial Instruments and Risk Management.

Transaction costs associated with financial assets and liabilities that are designated as held-for-trading are recognized immediately in results of operations. All financial instrument transactions are recorded at trade date.

**Derivative Instruments and Hedge Accounting**

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2013. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

**Employee Future Benefits**

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

Hydro One recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment funds are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets 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, including Hydro One Remote Communities, but not including Hydro One Brampton Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit 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*

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of the these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's 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 accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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 Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its 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. 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 Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement 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 Remote Communities records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 Remote

Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

## 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 and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on its financial position. This ASU 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 Company's 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 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 Financial Statements.

## 4. DEPRECIATION AND AMORTIZATION

| *Year ended December 31 (thousands of dollars)* | 2013 | 2012 |
|---|---|---|
| Depreciation of property, plant and equipment | 2,564 | 2,946 |
| Asset removal costs | 589 | 560 |
| Gain on disposition of property, plant and equipment | – | (2) |
| Amortization of regulatory assets | 1,656 | 2,515 |
| | 4,809 | 6,019 |

## 5. FINANCING CHARGES

| *Year ended December 31 (thousands of dollars)* | 2013 | 2012 |
|---|---|---|
| Interest on long-term debt | 1,237 | 1,237 |
| Interest on inter-company demand facility | 216 | 83 |
| Amortization of hedging losses | 13 | 12 |
| Other | 14 | 5 |
| Less: Interest capitalized on construction in progress | (376) | (321) |
| | 1,104 | 1,016 |

## 6. PROVISION FOR PILS

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 (thousands of dollars)* | 2013 | 2012 |
|---|---|---|
| Loss before recovery of PILs | (1,091) | (1,436) |
| Canadian Federal and Ontario statutory income tax rate | 26.50% | 26.50% |
| Recovery of PILs at statutory rate | (289) | (381) |
| | | |
| Increase (decrease) resulting from: | | |
| | | |
| Net temporary differences included in amounts charged to customers: | | |
| Depreciation and amortization in excess of capital cost allowance | 469 | 913 |
| Environmental expenditures | (439) | (667) |
| Overheads capitalized for accounting but deducted for tax purposes | (82) | (102) |
| Interest capitalized for accounting but deducted for tax purposes | (100) | (85) |
| Post-retirement and post-employment benefit expense in excess of cash payments | 135 | 74 |
| RRPR variance account | (318) | (1,029) |
| Pension contribution in excess of pension expense | (90) | (107) |
| Other | 56 | (15) |
| Net temporary differences | (369) | (1,018) |
| Prior year adjustments | (332) | – |
| Rate difference on loss carryback | (110) | – |
| Other permanent differences | 9 | (37) |
| Total recovery of PILs | (1,091) | (1,436) |
| | | |
| Current recovery of PILs | (1,091) | (1,436) |
| Deferred recovery of PILs | – | – |
| Total recovery of PILs | (1,091) | (1,436) |
| | | |
| Effective income tax rate | 100% | 100% |

The recovery of payments in lieu of current income taxes of $1,091 thousand (2012 – $1,436 thousand) represents the amount that is recoverable from the OEFC with respect to current year income. The balance receivable from the OEFC at December 31, 2013 was $2,697 thousand (2012 – $1,589 thousand).

**Deferred Income Tax Assets**

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 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| **Deferred income tax assets** | | |
| Environmental expenditures | 4,840 | 4,283 |
| Post-retirement and post-employment benefits expense in excess of cash payments | 4,466 | 4,266 |
| Depreciation and amortization in excess of capital cost allowance | 1,845 | 2,263 |
| Regulatory amounts not recognized for tax | (6,615) | (5,726) |
| Debt costs and hedging losses recognized for tax but not for accounting purposes | (189) | (245) |
| Total deferred income tax assets | 4,347 | 4,841 |
| Less: current portion | 108 | 108 |
| | 4,239 | 4,733 |

During 2013, there was no change in the rate applicable to future taxes (2012 – a change in rate applicable to future rates resulted in a $464 thousand increase to deferred tax liability).

## 7. ACCOUNTS RECEIVABLE

| *December 31 (thousands of dollars)* | Current accounts receivable | Long-term accounts receivable | Total |
|---|---|---|---|
| **2013** | | | |
| Accounts receivable – billed | 3,887 | 674 | 4,561 |
| Accounts receivable – unbilled | 1,404 | – | 1,404 |
| Accounts receivable, gross | 5,291 | 674 | 5,965 |
| Allowance for doubtful accounts | (296) | – | (296) |
| Accounts receivable, net | 4,995 | 674 | 5,669 |
| **2012** | | | |
| Accounts receivable – billed | 2,963 | 423 | 3,386 |
| Accounts receivable – unbilled | 1,527 | – | 1,527 |
| Accounts receivable, gross | 4,490 | 423 | 4,913 |
| Allowance for doubtful accounts | (297) | (5) | (302) |
| Accounts receivable, net | 4,193 | 418 | 4,611 |

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2013 and 2012:

| *Year ended December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Allowance for doubtful accounts – January 1 | (302) | (658) |
| Write-offs | 95 | 222 |
| Adjustments to allowance for doubtful accounts | (89) | 134 |
| Allowance for doubtful accounts – December 31 | (296) | (302) |

## 8. PROPERTY, PLANT AND EQUIPMENT

| *December 31 (thousands of dollars)* | Costs | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| **2013** | | | | |
| Generation | 41,616 | 19,517 | 2,716 | 24,815 |
| Distribution | 8,394 | 1,748 | 596 | 7,242 |
| Administration and Service | 10,545 | 1,991 | 161 | 8,715 |
| | 60,555 | 23,256 | 3,473 | 40,772 |
| **2012** | | | | |
| Generation | 38,803 | 22,056 | 6,764 | 23,511 |
| Distribution | 7,757 | 1,785 | 315 | 6,287 |
| Administration and Service | 9,803 | 1,938 | 171 | 8,036 |
| | 56,363 | 25,779 | 7,250 | 37,834 |

Financing charges capitalized on property, plant and equipment under construction were $376 thousand in 2013 (2012 – $321 thousand).

## 9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

| *December 31 (thousands of dollars)* | 2013 | 2012 |
|---|---|---|
| **Regulatory assets:** | | |
| Environmental | 13,426 | 11,880 |
| Post-retirement and post-employment benefits | 2,939 | 3,144 |
| RRPR variance account | 1,985 | 787 |
| IFRS transition cost variance | – | 72 |
| Total regulatory assets | 18,350 | 15,883 |
| Less: current portion | 2,427 | 1,823 |
| | 15,923 | 14,060 |
| **Regulatory liabilities:** | | |
| Deferred income tax regulatory liability | 4,347 | 4,841 |
| Total regulatory liabilities | 4,347 | 4,841 |
| Less: current portion | 108 | 108 |
| | 4,239 | 4,733 |

### Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. Management considers it probable that such expenditures will be recovered in the future through the rate-setting process, and as such, the Company has recorded an equivalent amount as a regulatory asset. In 2013, this regulatory asset increased by $2,872 thousand (2012 – decreased by $583 thousand) to reflect related changes in the Company's environmental liabilities. 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 Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2013 operation, maintenance and administration expenses would have been higher by $2,872 thousand (2012 – lower by $583 thousand). In addition, 2013 amortization expense would have been lower by $1,656 thousand (2012 – $2,515 thousand), and 2013 financing charges would have been higher by $330 thousand (2012 – $399 thousand).

**Post-Retirement and Post-Employment Benefits**

The Company 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 $205 thousand (2012 – lower by $1,941 thousand).

**RRPR Variance Account**

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2013, the Company has recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of net RRRP amounts received. At December 31, 2012, net RRRP amounts received were also lower than amounts required to achieve breakeven net income, and as such, a regulatory asset was also recognized. In the absence of rate-regulated accounting, 2013 revenue would have been lower by $1,198 thousand (2012 – $3,957 thousand).

**IFRS Transition Costs Variance**

Hydro One Remote Communities recorded an asset for the variance between its one-time incremental costs incurred in its uncompleted transition to IFRS and amounts included in rates in respect of this project. In 2013, the company decided not to seek recovery of this amount from rate payers and it was included in the Statement of Operations.

**Deferred Income Tax Regulatory 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 recovery of PILs would have been lower by approximately $367 thousand (2012 – $771 thousand).

## 10. LONG-TERM DEBT

Long-term debt represents a note payable to Hydro One. The note was issued on May 19, 2005, with a carrying value of $23,000 thousand and interest at a rate of 5.38% per annum. The note matures on May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999 in consideration of the purchase price of Hydro One Remote Communities' net assets.

On issuance of this note, $115 thousand of transaction costs and a $31 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

## 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.

Hydro One Remote Communities 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 Remote Communities 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 Company's 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 Hierarchy**

The fair value hierarchy of financial assets and liabilities at December 31, 2013 and 2012 are as follows:

| *December 31, 2013 (thousands of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 18,031 | 18,031 | 18,031 | – | – |
| Long-term debt | 23,000 | 25,450 | – | 25,450 | – |
| | 41,031 | 43,481 | 18,031 | 25,450 | – |

| *December 31, 2012 (thousands of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 11,212 | 11,212 | 11,212 | – | – |
| Long-term debt | 23,000 | 28,486 | – | 28,486 | – |
| | 34,212 | 39,698 | 11,212 | 28,486 | – |

The fair value 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 foreign exchange risk is currently not significant, although Hydro One could in the future decide to issue and allocate foreign currency-denominated debt to the Company, along with an allocation of the resulting foreign exchange gains and losses. The Company is exposed to fluctuations in interest rates related

to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the bankers' acceptance rate, plus 0.15%.

*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 Remote Communities 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 Company's total provision for bad debts was $296 thousand (2012 – $302 thousand). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2013, approximately 47% of the Company's current accounts receivable were aged more than 60 days (2012 – 34%). Sufficient allowances have been recorded to reflect the risk of potential credit losses.

*Liquidity Risk*

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities 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 $5,657 thousand (2012 – $6,863 thousand) are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2013, Hydro One Remote Communities had long-term debt in the principal l amount of $23,000 thousand (2012 – $23,000 thousand). No long-term debt matures during the next year. Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $1,237 thousand (2012 – $1,237 thousand). Principal repayments and interest payments are summarized by the number of years to maturity in the following table.

| Years to Maturity | Principal Outstanding on Long-term Debt *(thousands of dollars)* | Interest Payments *(thousands of dollars)* |
|---|---|---|
| 1 year | – | 1,237 |
| 2 years | – | 1,237 |
| 3 years | – | 1,237 |
| 4 years | – | 1,237 |
| 5 years | – | 1,237 |
| | – | 6,185 |
| 6 – 10 years | – | 6,185 |
| Over 10 years | 23,000 | 15,468 |
| | 23,000 | 27,838 |

## 12. 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. 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 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.

Company and employees' 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, Hydro One Remote Communities charged $775 thousand (2012 – $537 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $250 thousand (2012 – $223 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2013 were $264 thousand (2012 – $259 thousand). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $205 thousand (2012 – increased by $1,941 thousand) and recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Accrued liabilities | 300 | 300 |
| Post-retirement and post-employment benefit liability | 12,088 | 11,532 |
| | 12,388 | 11,832 |

## 13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2013 and 2012:

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Environmental liabilities, January 1 | 11,880 | 14,579 |
| Interest accretion | 330 | 399 |
| Expenditures | (1,656) | (2,515) |
| Revaluation adjustment | 2,872 | (583) |
| Environmental liabilities, December 31 | 13,426 | 11,880 |
| Less: current portion | 2,427 | 1,823 |
| | 10,999 | 10,057 |

The following table illustrates 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 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Undiscounted environmental liabilities, December 31 | 14,014 | 12,503 |
| Less: discounting accumulated liabilities to present value | 588 | 623 |
| Discounted environmental liabilities, December 31 | 13,426 | 11,880 |

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2013 and in total thereafter are as follows: 2014 – $2,427 thousand; 2015 – $2,175 thousand; 2016 – $2,844 thousand; 2017 – $1,261 thousand; 2018 – $1,651 thousand; and thereafter – $3,653 thousand. These expenditures are expected to be incurred over the period from 2014 to 2020.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting its expectation that future environmental costs will be recoverable in rates.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.57% to 4.87%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

As a result of its annual review of the environmental liabilities, the Company recorded a revaluation adjustment to increase the LAR environmental liability by $2,872 thousand (2012 – decrease by $583 thousand).

## 14. SHARE CAPITAL

### Common Shares

The Company has 2 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

### Dividends

The Company has no retained earnings and does not pay dividends under its breakeven business model.

## 15. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities 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 Hydro One Remote Communities because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One Remote Communities are described below.

Hydro One Remote Communities receives amounts for RRRP from the IESO. RRRP amounts received for the year ended December 31, 2013 were $33,046 thousand (2012 – $27,549 thousand). Consistent with its breakeven business model, the Company recognized $34,245 thousand as RRRP revenue in 2013 (2012 – $31,506 thousand). This 2013 revenue exceeded

amounts received by $1,199 thousand (2012 – $3,957 thousand) and the RRPR variance account balance was adjusted by this amount.

The recovery of PILs was received or receivable from the OEFC.

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

| *December 31 (thousands of dollars)* | 2013 | 2012 |
|---|---|---|
| Accounts receivable | 97 | 88 |
| Income tax receivable | 2,697 | 1,589 |

Transactions with 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.

**Hydro One and Subsidiaries**

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its other 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 corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2013 revenues include $195 thousand (2012 – $130 thousand) related to the provision of services to Hydro One and its other subsidiaries. 2013 operation, maintenance and administration costs include $3,475 thousand (2012 – $2,607 thousand) related to the purchase of services from Hydro One and its other subsidiaries.

The Company's long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One and its other subsidiaries. Financing charges include interest expense on the long-term debt in the amount of $1,237 thousand (2012 – $1,237 thousand), and interest expense on the inter-company demand facility in the amount of $216 thousand (2012 – $83 thousand). At December 31, 2013, the Company had accrued interest payable to Hydro One totaling $142 thousand (2012 – $142 thousand).

## 16. STATEMENTS OF CASH FLOWS

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

| *Year ended December 31 (thousands of dollars)* | 2013 | 2012 |
|---|---|---|
| Accounts receivable | (802) | (258) |
| Materials and supplies | 443 | 638 |
| Income taxes receivable | (1,108) | (1,426) |
| Long-term accounts receivable | (256) | (49) |
| Accounts payable | (284) | (443) |
| Accrued liabilities | (1,526) | 91 |
| Post-retirement and post-employment benefit liability | 760 | 500 |
| | (2,773) | (947) |
| **Supplementary information:** | | |
| Net interest paid | 1,453 | 1,320 |

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any PILs paid are fully recovered.

## 17. CONTINGENCIES

### Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

### Transfer of Assets

The transfer orders by which the Company acquired Ontario Hydro's remote communities business on April 1, 1999 did not transfer title to some assets located on lands held for First Nation bands under the *Indian Act* (Canada). Currently, OEFC holds legal title to these assets and the Company manages them until the Company has obtained necessary authorizations to complete the title transfer. To occupy reserve land, 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 band, OEFC and any First Nation individuals who have occupancy rights. The agreement includes provisions whereby the First Nation band consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. 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 the First Nation bands. In 2013, the Company paid approximately $2 million (2012 – $1 million) in respect of these consents. OEFC will continue to hold these assets until the Company is able to negotiate agreements with the First Nation bands and occupants. If the Company cannot reach satisfactory agreements and obtain federal permits, the Company may have to relocate these assets from the reserve lands to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on the Company's net income if the Company is not able to recover them in future rate orders.

## 18. COMMITMENTS

### Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years.

At December 31, 2013, the future minimum lease payments under this operating lease are as follows:

| *Year ended December 31 (thousands of dollars)* | **2013** |
|---|---|
| Within one year | 120 |
| After one year but not more than five years | 510 |
| More than five years | 600 |
| | 1,230 |

During the year ended December 31, 2013, the Company made upfront lease payments totalling $1 million which is being amortized based over the contractual term of the lease.

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**SCHEDULE 100**

Form identifier 100

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

## Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 11,963,000 | 9,892,000 |
| | Total tangible capital assets | 2008 | + | 64,028,000 | 63,613,000 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 23,256,000 | 25,779,000 |
| | Total intangible capital assets | 2178 | + | | |
| | Total accumulated amortization of intangible capital assets | 2179 | – | | |
| | Total long-term assets | 2589 | + | 20,960,000 | 19,339,000 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 73,695,000 | 67,065,000 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 23,939,000 | 18,325,000 |
| | Total long-term liabilities | 3450 | + | 50,325,000 | 49,322,000 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 74,264,000 | 67,647,000 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | -569,000 | -582,000 |
| | **Total liabilities and shareholder equity** | 3640 | = | 73,695,000 | 67,065,000 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | | |

* Generic item

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**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | Ontario Hydro Remote Communities Service Company Inc. |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Income statement information** | | | | |
| | Total sales of goods and services | 8089 | + | 50,035,000 | 46,766,000 |
| | Cost of sales | 8518 | – | 25,568,000 | 24,306,000 |
| | **Gross profit/loss** | 8519 | = | 24,467,000 | 22,460,000 |
| | Cost of sales | 8518 | + | 25,568,000 | 24,306,000 |
| | Total operating expenses | 9367 | + | 25,558,000 | 23,896,000 |
| | **Total expenses** (mandatory field) | 9368 | = | 51,126,000 | 48,202,000 |
| | Total revenue (mandatory field) | 8299 | + | 50,035,000 | 46,766,000 |
| | Total expenses (mandatory field) | 9368 | – | 51,126,000 | 48,202,000 |
| | **Net non-farming income** | 9369 | = | -1,091,000 | -1,436,000 |
| | **Farming income statement information** | | | | |
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | -1,091,000 | -1,436,000 |
| | **Total other comprehensive income** | 9998 | = | 13,000 | 12,000 |
| | **Extraordinary items and income (linked to Schedule 140)** | | | | |
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | -1,091,000 | -1,436,000 |
| | Future (deferred) income tax provision | 9995 | – | | |
| | Total – Other comprehensive income | 9998 | + | 13,000 | 12,000 |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 13,000 | 12,000 |

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**Schedule 141**

# Notes checklist

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? .......... **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? .......... **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

**Note**

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: .......... **198**

Completed an auditor's report .......... 1 [X]

Completed a review engagement report .......... 2 [ ]

Conducted a compilation engagement .......... 3 [ ]

## Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? .......... **099** 1 Yes [ ] 2 No [X]

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: .......... **110**

Prepared the tax return (financial statements prepared by client) .......... 1 [X]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) .......... 2 [ ]

Were notes to the financial statements prepared? .......... **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? .......... **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? .......... **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? .......... **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? .......... **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? .......... **108** 1 Yes [ ] 2 No [X]

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . 200 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | **In net income** Increase (decrease) | | **In OCI** Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . 255 1 Yes [X] 2 No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . . 260 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . 265 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

**SCHEDULE 100**

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

### Assets – lines 1000 to 2599

| | | | | | |
|---|---|---|---|---|---|
| 1062 | 4,995,000 | 1066 | 2,697,000 | 1122 | 1,736,000 |
| 1480 | 2,427,000 | 1481 | 108,000 | 1599 | 11,963,000 |
| 1740 | 50,010,000 | 1741 | -21,265,000 | 1900 | 10,545,000 |
| 1901 | -1,991,000 | 1920 | 3,473,000 | 2008 | 64,028,000 |
| 2009 | -23,256,000 | 2420 | 16,721,000 | 2421 | 4,239,000 |
| 2589 | 20,960,000 | 2599 | 73,695,000 | | |

### Liabilities – lines 2600 to 3499

| | | | | | |
|---|---|---|---|---|---|
| 2620 | 5,657,000 | 2629 | 142,000 | 2860 | 18,031,000 |
| 2960 | 109,000 | 3139 | 23,939,000 | 3140 | 23,000,000 |
| 3320 | 15,237,000 | 3321 | 12,088,000 | 3450 | 50,325,000 |
| 3499 | 74,264,000 | | | | |

### Shareholder equity – lines 3500 to 3640

| | | | | | |
|---|---|---|---|---|---|
| 3580 | -569,000 | 3620 | -569,000 | 3640 | 73,695,000 |

### Retained earnings – lines 3660 to 3849

| | |
|---|---|
| 3849 | 0 |

**SCHEDULE 125**

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

## Description

Operating name . . . . . . . . **0001** Ontario Hydro Remote Communities Service Company Inc.

Sequence number . . . . . . . **0003** 01

## Other comprehensive income – lines 7000 to 7020

| | |
|---|---|
| **7020** | 13,000 |

## Revenue – lines 8000 to 8299

| | | | | | |
|---|---|---|---|---|---|
| **8000** | 50,035,000 | **8089** | 50,035,000 | **8299** | 50,035,000 |

## Cost of sales – lines 8300 to 8519

| | | | | | |
|---|---|---|---|---|---|
| **8408** | 25,568,000 | **8518** | 25,568,000 | **8519** | 24,467,000 |

## Operating expenses – lines 8520 to 9369

| | | | | | |
|---|---|---|---|---|---|
| **8670** | 4,809,000 | **8714** | 1,104,000 | **9270** | 19,645,000 |
| **9367** | 25,558,000 | **9368** | 51,126,000 | **9369** | -1,091,000 |

## Extraordinary items and taxes – lines 9970 to 9999

| | | | | | |
|---|---|---|---|---|---|
| **9970** | -1,091,000 | **9990** | -1,091,000 | **9998** | 13,000 |
| **9999** | 13,000 | | | | |

Canada Revenue Agency / Agence du revenu du Canada

# Net Income (Loss) for Income Tax Purposes

**SCHEDULE 1**

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

| | | | | |
|---|---|---|---|---|
| Amount calculated on line 9999 from Schedule 125 | | | | 13,000 A |
| **Add:** | | | | |
| Provision for income taxes – current | | 101 | -1,091,000 | |
| Amortization of tangible assets | | 104 | 4,809,000 | |
| Non-deductible meals and entertainment expenses | | 121 | 32,011 | |
| Reserves from financial statements – balance at the end of the year | | 126 | 23,828,275 | |
| Subtotal of additions | | | 27,578,286 ▶ | 27,578,286 |
| **Other additions:** | | | | |
| Debt issue expense | | 208 | 15,869 | |
| **Miscellaneous other additions:** | | | | |
| 600 OPEB US GAAP Valuation | | 290 | 205,194 | |
| 601 Unpaid Bonus Accrual | | 291 | 8,461 | |
| 602 2013 Ontario Co-op & Apprentice credits | | 292 | 30,604 | |
| 604 Computer software expensed | 1,011 | | | |
| Total | 1,011 | 294 | 1,011 | |
| Subtotal of other additions | | 199 | 261,139 ▶ | 261,139 |
| **Total additions** | | 500 | 27,839,425 ▶ | 27,839,425 B |
| Amount A **plus** amount B | | | | 27,852,425 |
| **Deduct:** | | | | |
| Capital cost allowance from Schedule 8 | | 403 | 2,826,199 | |
| Reserves from financial statements – balance at the beginning of the year | | 414 | 22,852,881 | |
| Subtotal of deductions | | | 25,679,080 ▶ | 25,679,080 |
| **Other deductions:** | | | | |
| Non-taxable/deductible other comprehensive income items | | 347 | 13,000 | |
| **Miscellaneous other deductions:** | | | | |
| 700 Reverse Environmental interest & valuation adjusts in S13 | | 390 | 3,202,325 | |
| 703 Removal expense added back via depreciation | 213,176 | | | |
| Total | 213,176 | 393 | 213,176 | |
| 704 Refer to supporting schedule | 1,022,539 | | | |
| OPEB costs capitalized | 246,812 | | | |
| Total | 1,269,351 | 394 | 1,269,351 | |
| Subtotal of other deductions | | 499 | 4,697,852 ▶ | 4,697,852 |
| **Total deductions** | | 510 | 30,376,932 ▶ | 30,376,932 |
| **Net income (loss) for income tax purposes** – enter on line 300 of the T2 return | | | | -2,524,507 |

T2 SCH 1 E (12)

Canada

# Attached Schedule with Total

Line 208 – Debt issue expense

Title Line 208 – Debt issue expense

| Description | Amount | |
|---|---|---|
| Amortization underwriting fee (761780) | 2,251 | 00 |
| Amortization of Hedge loss (761770) | 13,010 | 00 |
| Bond Discount (761120,761130) | 608 | 00 |
| **Total** | 15,869 | 00 |

# Attached Schedule with Total

Line 704 – Amount

Title Line 704 – Amount

| Description | Amount |
|---|---|
| Capitalized interest | 376,006 00 |
| Capitalized overhead | 308,916 00 |
| Pension costs capitalized | 337,617 00 |
| | |
| **Total** | 1,022,539 00 |

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 4**

# Corporation Loss Continuity and Application

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the federal *Income Tax Act.*

## Part 1 – Non-capital losses

**Determination of current-year non-capital loss**

| | | | | |
|---|---|---|---|---|
| Net income (loss) for income tax purposes | | | -2,524,507 | A |
| **Deduct:** (increase a loss) | | | | |
| Net capital losses deducted in the year (enter as a positive amount) | | a | | |
| Taxable dividends deductible under section 112 or subsection 113(1) or 138(6) | | b | | |
| Amount of Part VI.1 tax deductible | | c | | |
| Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2) | | d | | |
| Subtotal (total of amounts a to d) | | | | B |
| Subtotal (amount A **minus** amount B; if positive, enter "0") | | | -2,524,507 | C |
| **Deduct:** (increase a loss) | | | | |
| Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions | | | | D |
| Subtotal (amount C **minus** amount D) | | | -2,524,507 | E |
| **Add:** (decrease a loss) | | | | |
| Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss) | | | | F |
| Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0") | | | -2,524,507 | G |

If amount G is negative, enter it on line 110 as a positive.

**Continuity of non-capital losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Non-capital loss at the end of the previous tax year | | | e | | |
| **Deduct:** Non-capital loss expired* | 100 | | f | | |
| Non-capital losses at the beginning of the tax year (amount e **minus** amount f) | 102 | | | | H |
| **Add:** | | | | | |
| Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation | 105 | | g | | |
| Current-year non-capital loss (from amount G) | 110 | 2,524,507 | h | | |
| Subtotal (amount g **plus** amount h) | | 2,524,507 | | 2,524,507 | I |
| Subtotal (amount H **plus** amount I) | | | | 2,524,507 | J |

* A non-capital loss expires as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004;
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004; and
- after **10** tax years if it arose in a tax year ending after March 22, 2004.

## Part 1 – Non-capital losses (continued)

**Deduct:**

| | | | | | |
|---|---|---|---|---|---|
| Other adjustments (includes adjustments for an acquisition of control) | 150 | | i | | |
| Section 80 – Adjustments for forgiven amounts | 140 | | j | | |
| Subsection 111(10) – Adjustments for fuel tax rebate | | | j.1 | | |
| Non-capital losses of previous tax years applied in the current tax year<br>Enter amount k on line 331 of the T2 return. | 130 | | k | | |
| Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax** | 135 | | l | | |
| Subtotal (total of amounts i to l) | | | | | K |
| Non-capital losses before any request for a carryback (amount J **minus** amount K) | | | | 2,524,507 | L |

**Deduct – Request to carry back non-capital loss to:**

| | | | | | |
|---|---|---|---|---|---|
| First previous tax year to reduce taxable income | 901 | | m | | |
| Second previous tax year to reduce taxable income | 902 | | n | | |
| Third previous tax year to reduce taxable income | 903 | 2,435,715 | o | | |
| First previous tax year to reduce taxable dividends subject to Part IV tax | 911 | | p | | |
| Second previous tax year to reduce taxable dividends subject to Part IV tax | 912 | | q | | |
| Third previous tax year to reduce taxable dividends subject to Part IV tax | 913 | | r | | |
| Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r) | | 2,435,715 | | 2,435,715 | M |
| Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M) | 180 | | | 88,792 | N |

** Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation.*

## Part 2 – Capital losses

**Continuity of capital losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Capital losses at the end of the previous tax year | 200 | | a | | |
| Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation | 205 | | b | | |
| Subtotal (amount a **plus** amount b) | | | | | A |
| **Deduct:** | | | | | |
| Other adjustments (includes adjustments for an acquisition of control) | 250 | | c | | |
| Section 80 – Adjustments for forgiven amounts | 240 | | d | | |
| Subtotal (amount c **plus** amount d) | | | | | B |
| Subtotal (amount A **minus** amount B) | | | | | C |
| **Add:** Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*) | 210 | | | | D |
| Unused non-capital losses that expired in the tax year* | | | e | | |
| Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year** | | | f | | |
| Enter amount e or f, whichever is less | 215 | | | | |
| ABILs expired as non-capital loss: line 215 **divided** by 0.500000 | 220 | | | | E |
| Subtotal (total of amounts C to E) | | | | | F |

**Note**

If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

## Part 2 – Capital losses (continued)

**Deduct:** Capital losses from previous tax years applied against the current-year net capital gain*** . . . . . . . . . . . . . . . . . . **225** ______ G

Capital losses before any request for a carryback (amount F **minus** amount G) ______ H

**Deduct – Request to carry back capital loss to******:

| | Capital gain (100%) | | Amount carried back (100%) | | | |
|---|---|---|---|---|---|---|
| First previous tax year | | 951 | | g | | |
| Second previous tax year | | 952 | | h | | |
| Third previous tax year | | 953 | | i | | |
| | Subtotal (total of amounts g to i) | | | ▶ | | I |

Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I) **280** ______ J

*** To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

**** On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

## Part 3 – Farm losses

**Continuity of farm losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Farm losses at the end of the previous tax year | | | a | | |
| **Deduct:** Farm loss expired* | 300 | | b | | |
| Farm losses at the beginning of the tax year (amount a **minus** amount b) | 302 | | ▶ | | A |
| **Add:** | | | | | |
| Farm losses transferred on the amalgamation or the windup of a subsidiary corporation | 305 | | c | | |
| Current-year farm loss (amount F in Part 1) | 310 | | d | | |
| Subtotal (amount c **plus** amount d) | | | ▶ | | B |
| Subtotal (amount A **plus** amount B) | | | | | C |
| **Deduct:** | | | | | |
| Other adjustments (includes adjustments for an acquisition of control) | 350 | | e | | |
| Section 80 – Adjustments for forgiven amounts | 340 | | f | | |
| Farm losses of previous tax years applied in the current tax year<br>Enter amount g on line 334 of the T2 return. | 330 | | g | | |
| Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax** | 335 | | h | | |
| Subtotal (total of amounts e to h) | | | ▶ | | D |
| Farm losses before any request for a carryback (amount C **minus** amount D) | | | | | E |
| **Deduct – Request to carry back farm loss to:** | | | | | |
| First previous tax year to reduce taxable income | 921 | | i | | |
| Second previous tax year to reduce taxable income | 922 | | j | | |
| Third previous tax year to reduce taxable income | 923 | | k | | |
| First previous tax year to reduce taxable dividends subject to Part IV tax | 931 | | l | | |
| Second previous tax year to reduce taxable dividends subject to Part IV tax | 932 | | m | | |
| Third previous tax year to reduce taxable dividends subject to Part IV tax | 933 | | n | | |
| Subtotal (total of amounts i to n) | | | ▶ | | F |
| Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F) | | | | 380 | G |

* A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

** Amount h is the total of lines 340 and 345 from Schedule 3.

## Part 4 – Restricted farm losses

**Current-year restricted farm loss**

| | | | | |
|---|---|---|---|---|
| Total losses for the year from farming business | 485 | | | A |
| **Minus** the deductible farm loss: | | | | |
| (amount A above ______ – $2,500) **divided** by 2 = ______ a | | | | |
| Amount a or $ 15,000 *, whichever is less | | | b | |
| | | 2,500 | c | |
| Subtotal (amount b **plus** amount c) | | 2,500 | | 2,500 B |
| Current-year restricted farm loss (amount A **minus** amount B) | | | | C |

**Continuity of restricted farm losses and request for a carryback**

| | | | | |
|---|---|---|---|---|
| Restricted farm losses at the end of the previous tax year | | | d | |
| **Deduct:** Restricted farm loss expired** | 400 | | e | |
| Restricted farm losses at the beginning of the tax year (amount d **minus** amount e) | 402 | | | D |
| **Add:** | | | | |
| Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation | 405 | | f | |
| Current-year restricted farm loss (from amount C) | 410 | | g | |
| Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes.* | | | | |
| Subtotal (amount f **plus** amount g) | | | | E |
| Subtotal (amount D **plus** amount E) | | | | F |
| **Deduct:** | | | | |
| Restricted farm losses from previous tax years applied against current farming income | 430 | | h | |
| Enter amount h on line 333 of the T2 return. | | | | |
| Section 80 – Adjustments for forgiven amounts | 440 | | i | |
| Other adjustments | 450 | | j | |
| Subtotal (total of amounts h to j) | | | | G |
| Restricted farm losses before any request for a carryback (amount F **minus** amount G) | | | | H |
| **Deduct – Request to carry back restricted farm loss to:** | | | | |
| First previous tax year to reduce farming income | 941 | | k | |
| Second previous tax year to reduce farming income | 942 | | l | |
| Third previous tax year to reduce farming income | 943 | | m | |
| Subtotal (total of amounts k to m) | | | | I |
| Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I) | 480 | | | J |

**Note**

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

** A restricted farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

## Part 5 – Listed personal property losses

**Continuity of listed personal property loss and request for a carryback**

| | | | | |
|---|---|---|---|---|
| Listed personal property losses at the end of the previous tax year | | a | | |
| **Deduct:** Listed personal property loss expired after seven tax years | 500 | b | | |
| Listed personal property losses at the beginning of the tax year (amount a **minus** amount b) | 502 | ▶ | | A |
| **Add:** Current-year listed personal property loss (from Schedule 6) | | | 510 | B |
| Subtotal (amount A **plus** amount B) | | | | C |
| **Deduct:** | | | | |
| Previous year personal property losses applied in the current tax year against listed personal property gains | 530 | c | | |
| Enter amount c on line 655 of Schedule 6. | | | | |
| Other adjustments | 550 | d | | |
| Subtotal (amount c **plus** amount d) | | ▶ | | D |
| Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D) | | | | E |
| **Deduct – Request to carry back listed personal property loss to:** | | | | |
| First previous tax year to reduce listed personal property gains | 961 | e | | |
| Second previous tax year to reduce listed personal property gains | 962 | f | | |
| Third previous tax year to reduce listed personal property gains | 963 | g | | |
| Subtotal (total of amounts e to g) | | ▶ | | F |
| Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F) | | | 580 | G |

## Part 7 – Limited partnership losses

### Current-year limited partnership losses

| 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|
| Partnership identifier 600 | Tax year ending YYYY/MM/DD 602 | Corporation's share of limited partnership loss 604 | Corporation's at-risk amount 606 | Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608 | Column 4 **minus** column 5 (if negative, enter "0") | Current-year limited partnership losses (column 3 **minus** 6) 620 |
| | | | | | | |
| | | | | | **Total** (enter this amount on line 222 of Schedule 1) | |

### Limited partnership losses from previous tax years that may be applied in the current year

| 8 | 9 | 10 | 11 | 12 | 13 | 14 |
|---|---|---|---|---|---|---|
| Partnership identifier 630 | Tax year ending YYYY/MM/DD 632 | Limited partnership losses at the end of the previous tax year 634 | Corporation's at-risk amount 636 | Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638 | Column 11 **minus** column 12 (if negative, enter "0") | Limited partnership losses that may be applied in the year (the lesser of columns 10 and 13) 650 |
| | | | | | | |

### Continuity of limited partnership losses that can be carried forward to future tax years

| 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|
| Partnership identifier 660 | Limited partnership losses at the end of the previous tax year 662 | Limited partnership losses transferred on an amalgamation or the windup of a subsidiary 664 | Current-year limited partnership losses (from column 7) 670 | Limited partnership losses applied in the current year (cannot be more than column 14) 675 | Current year limited partnership losses closing balance to be carried forward to future years (column 16 **plus** column 17 **plus** column 18 **minus** column 19) 680 |
| | | | | | |
| | | | **Total** (enter this amount on line 335 of the T2 return) | | |

**Note**

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

## Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 190 Yes ☐

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

**Note**

This election applies only for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for tax years that begin after the start of the wind-up.

# Non-Capital Loss Continuity Workchart

## Part 6 – Analysis of balance of losses by year of origin

### Non-capital losses – losses that can be carried forward over 20 years

| Year of origin | Balance at beginning of year | Loss incurred in current year | Adjustments and transfers | Loss carried back Parts I & IV | Applied to reduce | | Balance at end of year |
|---|---|---|---|---|---|---|---|
| | | | | | Taxable income | Part IV tax | |
| Current | N/A | 2,524,507 | | 2,435,715 | N/A | | 88,792 |
| 1st preceding taxation year 2012-12-31 | | N/A | | N/A | | | |
| 2nd preceding taxation year 2011-12-31 | | N/A | | N/A | | | |
| 3rd preceding taxation year 2010-12-31 | | N/A | | N/A | | | |
| 4th preceding taxation year 2009-12-31 | | N/A | | N/A | | | |
| 5th preceding taxation year 2008-12-31 | | N/A | | N/A | | | |
| 6th preceding taxation year 2007-12-31 | | N/A | | N/A | | | |
| 7th preceding taxation year 2006-12-31 | | N/A | | N/A | | | |
| 8th preceding taxation year 2005-12-31 | | N/A | | N/A | | | |
| 9th preceding taxation year 2004-12-31 | | N/A | | N/A | | | |
| 10th preceding taxation year 2003-12-31 | | N/A | | N/A | | | |
| 11th preceding taxation year 2002-12-31 | | N/A | | N/A | | | |
| 12th preceding taxation year 2001-12-31 | | N/A | | N/A | | | |
| 13th preceding taxation year 2000-12-31 | | N/A | | N/A | | | |
| 14th preceding taxation year 1999-12-31 | | N/A | | N/A | | | |
| 15th preceding taxation year 1999-03-31 | | N/A | | N/A | | | |
| 16th preceding taxation year 1998-03-31 | | N/A | | N/A | | | |
| 17th preceding taxation year 1997-03-31 | | N/A | | N/A | | | |
| 18th preceding taxation year 1996-03-31 | | N/A | | N/A | | | |
| 19th preceding taxation year 1995-03-31 | | N/A | | N/A | | | |
| 20th preceding taxation year 1994-03-31 | | N/A | | N/A | | | * |
| **Total** | | 2,524,507 | | 2,435,715 | | | 88,792 |

* **This balance expires this year and will not be available next year.**

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**Schedule 5**

# TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

| Corporation's name | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

## Part 1 – Allocation of taxable income

**100** ______________________ Enter the Regulation that applies (402 to 413).

| A<br>Jurisdiction<br>Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. * | | B<br>Total salaries and wages paid in jurisdiction | C<br>(B x taxable income**) / G | D<br>Gross revenue | E<br>(D x taxable income**) / H | F<br>Allocation of taxable income (C + E) x 1/2***<br>(where either G or H is nil, do not multiply by 1/2) |
|---|---|---|---|---|---|---|
| Newfoundland and Labrador | 003 1 Yes ☐ | 103 | | 143 | | |
| Newfoundland and Labrador offshore | 004 1 Yes ☐ | 104 | | 144 | | |
| Prince Edward Island | 005 1 Yes ☐ | 105 | | 145 | | |
| Nova Scotia | 007 1 Yes ☐ | 107 | | 147 | | |
| Nova Scotia offshore | 008 1 Yes ☐ | 108 | | 148 | | |
| New Brunswick | 009 1 Yes ☐ | 109 | | 149 | | |
| Quebec | 011 1 Yes ☐ | 111 | | 151 | | |
| Ontario | 013 1 Yes ☐ | 113 | | 153 | | |
| Manitoba | 015 1 Yes ☐ | 115 | | 155 | | |
| Saskatchewan | 017 1 Yes ☐ | 117 | | 157 | | |
| Alberta | 019 1 Yes ☐ | 119 | | 159 | | |
| British Columbia | 021 1 Yes ☐ | 121 | | 161 | | |
| Yukon | 023 1 Yes ☐ | 123 | | 163 | | |
| Northwest Territories | 025 1 Yes ☐ | 125 | | 165 | | |
| Nunavut | 026 1 Yes ☐ | 126 | | 166 | | |
| Outside Canada | 027 1 Yes ☐ | 127 | | 167 | | |
| **Total** | | 129 G | | 169 H | | |

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

**Notes:**
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

## Part 2 – Ontario tax payable, tax credits, and rebates

| Total taxable income | Income eligible for small business deduction | Provincial or territorial allocation of taxable income | Provincial or territorial tax payable before credits |
|---|---|---|---|
| | | | |

| | | | | |
|---|---|---|---|---|
| **Ontario basic income tax** (from Schedule 500) | 270 | | | |
| **Deduct:** Ontario small business deduction (from Schedule 500) | 402 | | | |
| Subtotal | | | ▶ | A6 |
| **Add:** | | | | |
| Ontario additional tax re Crown royalties (from Schedule 504) | 274 | | | |
| Ontario transitional tax debits (from Schedule 506) | 276 | | | |
| Recapture of Ontario research and development tax credit (from Schedule 508) | 277 | | | |
| Subtotal | | | ▶ | B6 |
| Subtotal (amount A6 **plus** amount B6) | | | | C6 |
| **Deduct:** | | | | |
| Ontario resource tax credit (from Schedule 504) | 404 | | | |
| Ontario tax credit for manufacturing and processing (from Schedule 502) | 406 | | | |
| Ontario foreign tax credit (from Schedule 21) | 408 | | | |
| Ontario credit union tax reduction (from Schedule 500) | 410 | | | |
| Ontario transitional tax credits (from Schedule 506) | 414 | | | |
| Ontario political contributions tax credit (from Schedule 525) | 415 | | | |
| Ontario tax credit for the purchase of vehicles that use natural gas as a fuel | | | | |
| Subtotal | | | ▶ | D6 |
| Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") | | | | E6 |
| **Deduct:** Ontario research and development tax credit (from Schedule 508) | | | 416 | |
| Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0") | | | | F6 |
| **Deduct:** Ontario corporate minimum tax credit (from Schedule 510) | | | 418 | |
| Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0") | | | | G6 |
| **Add:** | | | | |
| Ontario corporate minimum tax (from Schedule 510) | 278 | | | |
| Ontario special additional tax on life insurance corporations (from Schedule 512) | 280 | | | |
| Subtotal | | | ▶ | H6 |
| Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) | | | | I6 |
| **Deduct:** | | | | |
| Ontario qualifying environmental trust tax credit | 450 | | | |
| Ontario co-operative education tax credit (from Schedule 550) | 452 | 12,000 | | |
| Ontario apprenticeship training tax credit (from Schedule 552) | 454 | 18,604 | | |
| Ontario computer animation and special effects tax credit (from Schedule 554) | 456 | | | |
| Ontario film and television tax credit (from Schedule 556) | 458 | | | |
| Ontario production services tax credit (from Schedule 558) | 460 | | | |
| Ontario interactive digital media tax credit (from Schedule 560) | 462 | | | |
| Ontario sound recording tax credit (from Schedule 562) | 464 | | | |
| Ontario book publishing tax credit (from Schedule 564) | 466 | | | |
| Ontario innovation tax credit (from Schedule 566) | 468 | | | |
| Ontario business-research institute tax credit (from Schedule 568) | 470 | | | |
| Other Ontario tax credits | | | | |
| Subtotal | | 30,604 | ▶ | 30,604 J6 |
| **Net Ontario tax payable or refundable credit** (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255. | | | 290 | -30,604 K6 |

## Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

**Net provincial and territorial tax payable or refundable credits** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 255 -30,604

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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**SCHEDULE 8**

# CAPITAL COST ALLOWANCE (CCA)

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

| | 1 Class number (See Note) 200 | Description | 2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201 | 3 Cost of acquisitions during the year (new property must be available for use)* 203 | 4 Net adjustments** 205 | 5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207 | 6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211 | 7 Reduced undepreciated capital cost | 8 CCA rate % **** 212 | 9 Recapture of capital cost allowance (line 107 of Schedule 1) 213 | 10 Terminal loss (line 404 of Schedule 1) 215 | 11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217 | 12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | 17,529,689 | 525,536 | | 0 | 262,768 | 17,792,457 | 4 | 0 | 0 | 711,698 | 17,343,527 |
| 2. | 2 | | 523,488 | | | 0 | | 523,488 | 6 | 0 | 0 | 31,409 | 492,079 |
| 3. | 3 | | 743,061 | | | 0 | | 743,061 | 5 | 0 | 0 | 37,153 | 705,908 |
| 4. | 6 | | 2,798,765 | 2,068,214 | | 0 | 1,034,107 | 3,832,872 | 10 | 0 | 0 | 383,287 | 4,483,692 |
| 5. | 8 | | 867,600 | 215,156 | | 0 | 107,578 | 975,178 | 20 | 0 | 0 | 195,036 | 887,720 |
| 6. | 10 | | 373,003 | 35,011 | | 0 | 17,506 | 390,508 | 30 | 0 | 0 | 117,152 | 290,862 |
| 7. | 12 | | 2,572 | 351 | | 0 | 176 | 2,747 | 100 | 0 | 0 | 2,747 | 176 |
| 8. | 13 | Hillsport Water Well | 38,999 | | | 0 | | 38,999 | NA | 0 | 0 | 1,019 | 37,980 |
| 9. | 13 | Oba Water Well | 22,260 | | | 0 | | 22,260 | NA | 0 | 0 | 2,782 | 19,478 |
| 10. | 17 | | 9,888,184 | 4,254,564 | | 0 | 2,127,282 | 12,015,466 | 8 | 0 | 0 | 961,237 | 13,181,511 |
| 11. | 42 | | 191,858 | | | 0 | | 191,858 | 12 | 0 | 0 | 23,023 | 168,835 |
| 12. | 43.1 | | 614 | 981,967 | | 0 | 490,984 | 491,597 | 30 | 0 | 0 | 147,479 | 835,102 |
| 13. | 45 | | 1,225 | | | 0 | | 1,225 | 45 | 0 | 0 | 551 | 674 |
| 14. | 47 | | 2,512,031 | 224,212 | | 14 | 112,099 | 2,624,130 | 8 | 0 | 0 | 209,930 | 2,526,299 |
| 15. | 50 | | 3,083 | | | 0 | | 3,083 | 55 | 0 | 0 | 1,696 | 1,387 |
| | | **Totals** | 35,496,432 | 8,305,011 | | 14 | 4,152,500 | 39,648,929 | | | | 2,826,199 | 40,975,230 |

**Note:** Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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**SCHEDULE 9**

# RELATED AND ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

| | Name 100 | Country of residence (other than Canada) 200 | Business number (see note 1) 300 | Relationship code (see note 2) 400 | Number of common shares you own 500 | % of common shares you own 550 | Number of preferred shares you own 600 | % of preferred shares you own 650 | Book value of capital stock 700 |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Hydro One Inc. | | 86999 4731 RC0001 | 1 | | | | | |
| 2. | Hydro One Networks Inc. | | 87086 5821 RC0001 | 3 | | | | | |
| 3. | Hydro One Telecom Inc. | | 86800 1066 RC0001 | 3 | | | | | |
| 4. | Hydro One Telecom Link Limited | | 88786 7513 RC0001 | 3 | | | | | |
| 5. | Hydro One Brampton Networks Inc. | | 86486 7635 RC0001 | 3 | | | | | |
| 6. | Hydro One Lake Erie Link Managem | | 87892 1519 RC0001 | 3 | | | | | |
| 7. | Hydro One Lake Erie Link Company | | 87560 6519 RC0001 | 3 | | | | | |
| 8. | Hydro One B2M LP Inc. | | 81838 2046 RC0001 | 3 | | | | | |
| 9. | B2M GP Inc. | | 81838 1840 RC0001 | 3 | | | | | |
| 10. | Hydro One B2M Holdings Inc. | | 82217 7531 RC0001 | 3 | | | | | |
| 11. | 1908872 Ontario Inc. | | 82581 6838 RC0001 | 3 | | | | | |
| 12. | 1908873 Ontario Inc. | | 83392 0978 RC0001 | 3 | | | | | |
| 13. | 1893080 Ontario Inc. | | 82217 7333 RC0001 | 3 | | | | | |

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

# Continuity of financial statement reserves (not deductible)

## Financial statement reserves (not deductible)

| | Description | Balance at the beginning of the year | Transfer on an amalgamation or the wind-up of a subsidiary | Add | Deduct | Balance at the end of the year |
|---|---|---|---|---|---|---|
| 1 | OPEB Liability | 11,832,479 | | 555,363 | | 12,387,842 |
| 2 | RRPP Rev Var (427191) | -786,719 | | | 1,198,744 | -1,985,463 |
| 3 | Environmental Liability | 11,879,741 | | 1,546,155 | | 13,425,896 |
| 4 | Reg Asset - IFRS Costs | -72,620 | | | -72,620 | |
| 5 | | | | | | |
| | Reserves from Part 2 of Schedule 13 | | | | | |
| | **Totals** | 22,852,881 | | 2,101,518 | 1,126,124 | 23,828,275 |

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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**SCHEDULE 14**

# MISCELLANEOUS PAYMENTS TO RESIDENTS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

| | Name of recipient 100 | Address of recipient 200 | Royalties 300 | Research and development fees 400 | Management fees 500 | Technical assistance fees 600 | Similar payments 700 |
|---|---|---|---|---|---|---|---|
| 1 | Hydro One Networks Inc | 483 Bay Street<br><br>Toronto<br>ON CA<br>M5G 2P5 | | | 818,505 | | |
| 2 | Hydro One Inc. | 483 Bay Street<br><br>Toronto<br>ON CA<br>M5G 2P5 | | | 49,336 | | |

T2 SCH 14 (99)

Canada

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**Schedule 15**

# Deferred Income Plans

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

| | Type of plan (see note 1) 100 | Amount of contribution $ (see note 2) 200 | Registration number (RPP, RSUBP, PRPP, and DPSP only) 300 | Name of EPSP trust 400 | Address of EPSP trust 500 | T4PS slip(s) (see note 3) 600 |
|---|---|---|---|---|---|---|
| 1 | 1 | 1,401,481 | 1059104 | | | |

**Note 1**

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

**Note 2**

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . . . . . . . . . . . . . . . . 1,401,481 A

**Less:**

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 1,401,481 B

**Deductible amount for contributions to deferred income plans**
(amount A **minus** amount B) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . C

Enter amount C on line 417 of Schedule 1

**Note 3**

T4PS slip(s) filed by: 1 – Trustee
2 – Employer
(EPSP only)

T2 SCH 15 (13)

Canada

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**SCHEDULE 23**

# AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

**Column 1:** Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

**Column 2:** Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

**Column 3:** Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)

2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction

3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)

4 – Associated non-CCPC

5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

**Column 4:** Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

**Column 5:** Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

**Column 6:** Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

| Calendar year | Acceptable range |
|---|---|
| 2006 | maximum $300,000 |
| 2007 | $300,001 to $400,000 |

| Calendar year | Acceptable range |
|---|---|
| 2008 | maximum $400,000 |
| 2009 | $400,001 to $500,000 |

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

## Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 Year 2013

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 1 Yes [ ] 2 No [X]

| | 1 Names of associated corporations 100 | 2 Business Number of associated corporations 200 | 3 Association code 300 | 4 Business limit for the year (before the allocation) $ | 5 Percentage of the business limit % 350 | 6 Business limit allocated* $ 400 |
|---|---|---|---|---|---|---|
| 1 | Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 1 | 500,000 | | |
| 2 | Hydro One Inc. | 86999 4731 RC0001 | 1 | 500,000 | | |
| 3 | Hydro One Networks Inc. | 87086 5821 RC0001 | 1 | 500,000 | 100.0000 | 500,000 |
| 4 | Hydro One Telecom Inc. | 86800 1066 RC0001 | 1 | 500,000 | | |
| 5 | Hydro One Telecom Link Limited | 88786 7513 RC0001 | 1 | 500,000 | | |
| 6 | Hydro One Brampton Networks Inc. | 86486 7635 RC0001 | 1 | 500,000 | | |
| 7 | Hydro One Lake Erie Link Management Inc | 87892 1519 RC0001 | 1 | 500,000 | | |
| 8 | Hydro One Lake Erie Link Company Inc. | 87560 6519 RC0001 | 1 | 500,000 | | |
| 9 | Hydro One B2M LP Inc. | 81838 2046 RC0001 | 1 | 500,000 | | |
| 10 | B2M GP Inc. | 81838 1840 RC0001 | 1 | 500,000 | | |
| 11 | Hydro One B2M Holdings Inc. | 82217 7531 RC0001 | 1 | 500,000 | | |
| 12 | 1908872 Ontario Inc. | 82581 6838 RC0001 | 1 | 500,000 | | |
| 13 | 1908873 Ontario Inc. | 83392 0978 RC0001 | 1 | 500,000 | | |

| | 1<br>Names of associated corporations<br>100 | 2<br>Business Number of associated corporations<br>200 | 3<br>Asso-ciation code<br>300 | 4<br>Business limit for the year (before the allocation)<br>$ | 5<br>Percentage of the business limit<br>%<br>350 | 6<br>Business limit allocated*<br>$<br>400 | |
|---|---|---|---|---|---|---|---|
| 14 | 1893080 Ontario Inc. | 82217 7333 RC0001 | 1 | 500,000 | | | |
| | | | | Total | 100.0000 | 500,000 | A |

**Business limit reduction under subsection 125(5.1) of the ITA**

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

# Summary of Investment Tax Credit Carryovers

## Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

**Current year**

| | Addition current year (A) | Applied current year (B) | Claimed as a refund (C) | Carried back (D) | ITC end of year (A-B-C-D) |
|---|---|---|---|---|---|
| | | | | | |

**Prior years**

| Taxation year | ITC beginning of year (E) | Adjustments (F) | Applied current year (G) | ITC end of year (E-F-G) |
|---|---|---|---|---|
| 2012-12-31 | 849 | | | 849 |
| 2011-12-31 | | | | |
| 2010-12-31 | | | | |
| 2009-12-31 | | | | |
| 2008-12-31 | | | | |
| 2007-12-31 | | | | |
| 2006-12-31 | | | | |
| 2005-12-31 | | | | |
| 2004-12-31 | | | | |
| 2003-12-31 | | | | * |
| 2002-12-31 | | | | |
| 2001-12-31 | | | | |
| 2000-12-31 | | | | |
| 1999-12-31 | | | | |
| 1999-03-31 | | | | |
| 1998-03-31 | | | | |
| 1997-03-31 | | | | |
| 1996-03-31 | | | | |
| 1995-03-31 | | | | |
| 1994-03-31 | | | | * |
| **Total** | 849 | | | 849 |

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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**SCHEDULE 50**

# SHAREHOLDER INFORMATION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

| | Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) | Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") | Social insurance number | Trust number | Percentage common shares | Percentage preferred shares |
|---|---|---|---|---|---|---|
| | 100 | 200 | 300 | 350 | 400 | 500 |
| 1 | Hydro One Inc. | 86999 4731 RC0001 | | | 100.000 | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 53**

# GENERAL RATE INCOME POOL (GRIP) CALCULATION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

On: 2013-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

## Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

**2006 addition**

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 ..... 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   **If the answer to question 3 is yes, complete Part "GRIP addition for 2006".**

**Change in the type of corporation**

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   **If the answer to question 5 is yes, complete Part 4.**

**Amalgamation (first year of filing after amalgamation)**

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   **If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.**
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   **If the answer to question 7 is yes, complete Part 4.**
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   **If the answer to question 8 is yes, complete Part 3.**

**Winding-up**

9. Has the corporation wound-up a subsidiary in the preceding taxation year? ☐ Yes ☒ No
   **If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.**
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    **If the answer to question 10 is yes, complete Part 4.**
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    **If the answer to question 11 is yes, complete Part 3.**

## Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year . . . **100** 1,223,283 A

Taxable income for the year (DICs enter "0") * . . . **110** ______ B

Income for the credit union deduction * (amount E in Part 3 of Schedule 17) . . . **120** ______

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * . . . **130** ______

For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * . . . **140** ______

Subtotal (**add** lines 120, 130, and 140) ______ ► ______ C

Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0") . . . **150** ______

After-tax income (line 150 x general rate factor for the tax year ** 0.72 ) . . . **190** ______ D

Eligible dividends received in the tax year . . . **200** ______

Dividends deductible under section 113 received in the tax year . . . **210** ______

Subtotal (**add** lines 200 and 210) ______ ► ______ E

GRIP addition:

Becoming a CCPC (line PP from Part 4) . . . **220** ______

Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4) . . . **230** ______

Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4) . . . **240** ______

Subtotal (**add** lines 220, 230, and 240) ______ ► **290** ______ F

Subtotal (**add** lines A, D, E, and F) 1,223,283 G

Eligible dividends paid in the previous tax year . . . **300** ______

Excessive eligible dividend designations made in the previous tax year . . . **310** ______

**Note:** If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.

Subtotal (line 300 **minus** line 310) ______ ► ______ H

GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative) . . . **490** 1,223,283

Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2) . . . **560** 1,503,909

**GRIP at the end of the tax year** (line 490 **minus** line 560) . . . **590** -280,626

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

**First previous tax year** 2012-12-31

Taxable income before specified future tax consequences from the current tax year . . . ______ J1

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . ______ L1

Aggregate investment income (line 440 of the T2 return) . . . ______ M1

Subtotal (**add** lines K1, L1, and M1) ______ ► ______ N1

Subtotal (line J1 **minus** line N1) (if negative, enter "0") ______ ► ______ O1

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ____ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R1

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ____ S1

Subtotal (**add** lines Q1, R1, and S1) ____ ▶ ____ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ____ ▶ ____ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ____ V1

**GRIP adjustment for specified future tax consequences to the first previous tax year**

(line V1 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** ____

**Second previous tax year** 2011-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . ____ J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ L2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ____ M2

Subtotal (**add** lines K2, L2, and M2) ____ ▶ ____ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") ____ ▶ ____ O2

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ____ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ____ S2

Subtotal (**add** lines Q2, R2, and S2) ____ ▶ ____ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ____ ▶ ____ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ____ V2

**GRIP adjustment for specified future tax consequences to the second previous tax year**

(line V2 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **520** ____

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

**Third previous tax year** 2010-12-31

Taxable income before specified future tax consequences from the current tax year . . . 2,088,762 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ▶ ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 2,088,762 ▶ 2,088,762 O3

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| 2,435,715 | | | | | 2,435,715 |

Taxable income after specified future tax consequences . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ▶ ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ▶ ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") 2,088,762 V3

**GRIP adjustment for specified future tax consequences to the third previous tax year**
(line V3 **multiplied by** the general rate factor for the tax year 0.72 ) . . . **540** 1,503,909

**Total GRIP adjustment for specified future tax consequences to previous tax years:**
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . 1,503,909 W

Enter amount W on line 560.

## Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

**nb. 1** Post amalgamation . . . ☐ Post wind-up . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ▶ ______ DD

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)**
(line AA **minus** line DD) . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

**nb. 1** Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . . . . . . . ☐ Post wind-up . . . . . . . . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

| | | | |
|---|---|---|---|
| Cost amount to the corporation of all property immediately before the end of its previous/last tax year | | | FF |
| The corporation's money on hand immediately before the end of its previous/last tax year | | | GG |
| Unused and unexpired losses at the end of the corporation's previous/last tax year: | | | |
| Non-capital losses | | | |
| Net capital losses | | | |
| Farm losses | | | |
| Restricted farm losses | | | |
| Limited partnership losses | | | |
| Subtotal | | ► | HH |
| Subtotal (**add** lines FF, GG, and HH) | | | II |
| All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year | | JJ | |
| Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year | | KK | |
| All the corporation's reserves deducted in its previous/last tax year | | LL | |
| The corporation's capital dividend account immediately before the end of its previous/last tax year | | MM | |
| The corporation's low rate income pool immediately before the end of its previous/last tax year | | NN | |
| Subtotal (**add** lines JJ, KK, LL, MM, and NN) | | ► | OO |
| **GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC** (line II **minus** line OO) (if negative, enter "0") | | | PP |

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

| Rate | | Fraction | Days | | Result | Line |
|---|---|---|---|---|---|---|
| 0.68 | x | number of days in the tax year before January 1, 2010 / number of days in the tax year | / 365 | = | | QQ |
| 0.69 | x | number of days in the tax year in 2010 / number of days in the tax year | / 365 | = | | RR |
| 0.7 | x | number of days in the tax year in 2011 / number of days in the tax year | / 365 | = | | SS |
| 0.72 | x | number of days in the tax year after December 31, 2011 / number of days in the tax year | 365 / 365 | = | 0.720000000 | TT |

**General rate factor for the tax year** (total of lines QQ to TT) . . . . . . . . . . . . . . . . . . . . . 0.72000 UU

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**Schedule 510**

# Ontario Corporate Minimum Tax

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Determination of CMT applicability

| | | |
|---|---|---|
| Total assets of the corporation at the end of the tax year * | 112 | 73,695,000 |
| Share of total assets from partnership(s) and joint venture(s) * | 114 | |
| Total assets of associated corporations (amount from line 450 on Schedule 511) | 116 | 33,431,225,104 |
| Total assets (total of lines 112 to 116) | | 33,504,920,104 |
| Total revenue of the corporation for the tax year ** | 142 | 50,035,000 |
| Share of total revenue from partnership(s) and joint venture(s) ** | 144 | |
| Total revenue of associated corporations (amount from line 550 on Schedule 511) | 146 | 6,702,002,000 |
| Total revenue (total of lines 142 to 146) | | 6,752,037,000 |

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.
If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
– Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
– The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
– The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

## Part 2 – Adjusted net income/loss for CMT purposes

| | Line | Amount | | Line | Amount | |
|---|---|---|---|---|---|---|
| Net income/loss per financial statements * | | | | 210 | 13,000 | |
| **Add** (to the extent reflected in income/loss): | | | | | | |
| Provision for current income taxes/cost of current income taxes | 220 | | | | | |
| Provision for deferred income taxes (debits)/cost of future income taxes | 222 | | | | | |
| Equity losses from corporations | 224 | | | | | |
| Financial statement loss from partnerships and joint ventures | 226 | | | | | |
| Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act | 230 | | | | | |
| **Other additions** (see note below): | | | | | | |
| Share of adjusted net income of partnerships and joint ventures ** | 228 | | | | | |
| Total patronage dividends received, not already included in net income/loss | 232 | | | | | |
| 281 | 282 | | | | | |
| 283 | 284 | | | | | |
| Subtotal | | | ► | | | A |
| **Deduct** (to the extent reflected in income/loss): | | | | | | |
| Provision for recovery of current income taxes/benefit of current income taxes | 320 | 1,091,000 | | | | |
| Provision for deferred income taxes (credits)/benefit of future income taxes | 322 | | | | | |
| Equity income from corporations | 324 | | | | | |
| Financial statement income from partnerships and joint ventures | 326 | | | | | |
| Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act | 330 | | | | | |
| Dividends not taxable under section 83 of the federal Act (from Schedule 3) | 332 | | | | | |
| Gain on donation of listed security or ecological gift | 340 | | | | | |
| Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act *** | 342 | | | | | |
| Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act **** | 344 | | | | | |
| Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act ***** | 346 | | | | | |
| Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act | 348 | | | | | |
| **Other deductions** (see note below): | | | | | | |
| Share of adjusted net loss of partnerships and joint ventures ** | 328 | | | | | |
| Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3 | 334 | | | | | |
| Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss | 336 | | | | | |
| Patronage dividends paid (from Schedule 16) not already included in net income/loss | 338 | | | | | |
| 381 Other comprehensive income included in income | 382 | 13,000 | | | | |
| 383 | 384 | | | | | |
| 385 | 386 | | | | | |
| 387 | 388 | | | | | |
| 389 | 390 | | | | | |
| Subtotal | | 1,104,000 | ► | | 1,104,000 | B |
| Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B) | | | | 490 | -1,091,000 | |

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

**Note**

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

## Part 2 – Adjusted net income/loss for CMT purposes (continued)

- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.
- Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

## Part 3 – CMT payable

| | | | | |
|---|---|---|---|---|
| Adjusted net income for CMT purposes (line 490 in Part 2, if positive) | | **515** | | |
| **Deduct:** | | | | |
| CMT loss available (amount R from Part 7) | 1,551,765 | | | |
| **Minus:** Adjustment for an acquisition of control * | **518** | | | |
| Adjusted CMT loss available | 1,551,765 ▶ | | 1,551,765 | C |
| Net income subject to CMT calculation (if negative, enter "0") | | **520** | | |

Amount from line 520 ______ x (Number of days in the tax year before July 1, 2010 ______ / Number of days in the tax year 365) x 4 % = ______ 1

Amount from line 520 ______ x (Number of days in the tax year after June 30, 2010 365 / Number of days in the tax year 365) x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ 3

| | | | |
|---|---|---|---|
| Gross CMT: amount on line 3 above x OAF ** | **540** | | |
| **Deduct:** | | | |
| Foreign tax credit for CMT purposes *** | **550** | | |
| CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") | | | D |
| **Deduct:** | | | |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | | |
| Net CMT payable (if negative, enter "0") | | | E |

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

**** Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

**Ontario allocation factor** 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

## Part 4 – CMT credit carryforward

| | | | | |
|---|---|---|---|---|
| CMT credit carryforward at the end of the previous tax year * | | | G | |
| **Deduct:** | | | | |
| CMT credit expired * | 600 | | | |
| CMT credit carryforward at the beginning of the current tax year * (see note below) | | | ▶ 620 | |
| **Add:** | | | | |
| CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) | | | 650 | |
| CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) | | | | H |
| **Deduct:** | | | | |
| CMT credit deducted in the current tax year (amount P from Part 5) | | | | I |
| Subtotal (amount H **minus** amount I) | | | | J |
| **Add:** | | | | |
| Net CMT payable (amount E from Part 3) | | | | |
| SAT payable (amount O from Part 6 of Schedule 512) | | | | |
| Subtotal | | | ▶ | K |
| CMT credit carryforward at the end of the tax year (amount J **plus** amount K) | | | 670 | L |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

**Note:** If you entered an amount on line 620 or line 650, complete Part 6.

## Part 5 – CMT credit deducted from Ontario corporate income tax payable

| | | | | |
|---|---|---|---|---|
| CMT credit available for the tax year (amount H from Part 4) | | | | M |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | | 1 | |
| For a corporation that is not a life insurance corporation: | | | | |
| CMT after foreign tax credit deduction (amount D from Part 3) | | 2 | | |
| For a life insurance corporation: | | | | |
| Gross CMT (line 540 from Part 3) | | 3 | | |
| Gross SAT (line 460 from Part 6 of Schedule 512) | | 4 | | |
| The **greater** of amounts 3 and 4 | | 5 | | |
| **Deduct:** line 2 or line 5, whichever applies: | | | 6 | |
| Subtotal (if negative, enter "0") | | | ▶ | N |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | | | |
| **Deduct:** | | | | |
| Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) | | | 30,604 | |
| Subtotal (if negative, enter "0") | | | ▶ | O |
| CMT credit deducted in the current tax year (least of amounts M, N, and O) | | | | P |

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

## Part 6 – CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | CMT credit balance * |
|---|---|
| 10th previous tax year | 680 |
| 9th previous tax year | 681 |
| 8th previous tax year | 682 |
| 7th previous tax year | 683 |
| 6th previous tax year | 684 |
| 5th previous tax year | 685 |
| 4th previous tax year | 686 |
| 3rd previous tax year | 687 |
| 2nd previous tax year | 688 |
| 1st previous tax year | 689 |
| Total ** | |

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

## Part 7 – CMT loss carryforward

| | | | | |
|---|---|---|---|---|
| CMT loss carryforward at the end of the previous tax year * | | 1,551,765 Q | | |
| **Deduct:** | | | | |
| CMT loss expired * | 700 | | | |
| CMT loss carryforward at the beginning of the tax year * (see note below) | | 1,551,765 ▶ | 720 | 1,551,765 |
| **Add:** | | | | |
| CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) | | | 750 | |
| CMT loss available (line 720 **plus** line 750) | | | | 1,551,765 R |
| **Deduct:** | | | | |
| CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) | | | | |
| Subtotal (if negative, enter "0") | | | | 1,551,765 S |
| **Add:** | | | | |
| Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) | | | 760 | 1,091,000 |
| CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) | | | 770 | 2,642,765 T |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

**Note:** If you entered an amount on line 720 or line 750, complete Part 8.

## Part 8 – CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | Balance earned in a tax year ending before March 23, 2007 * | Balance earned in a tax year ending after March 22, 2007 ** |
|---|---|---|
| 10th previous tax year | 810 | 820 |
| 9th previous tax year | 811 | 821 |
| 8th previous tax year | 812 | 822 |
| 7th previous tax year | 813 | 823 |
| 6th previous tax year | 814 | 824 |
| 5th previous tax year | 815 | 825 |
| 4th previous tax year | 816 | 826 |
| 3rd previous tax year | 817 | 827 |
| 2nd previous tax year | 818 | 828 |
| 1st previous tax year | | 829 |
| Total *** | | |

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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**SCHEDULE 511**

# ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 1 | Hydro One Inc. | 86999 4731 RC0001 | 13,247,000,000 | 650,000,000 |
| 2 | Hydro One Networks Inc. | 87086 5821 RC0001 | 19,698,000,000 | 5,502,000,000 |
| 3 | Hydro One Telecom Inc. | 86800 1066 RC0001 | 76,876,000 | 80,880,000 |
| 4 | Hydro One Telecom Link Limited | 88786 7513 RC0001 | 1,111,000 | 442,000 |
| 5 | Hydro One Brampton Networks Inc. | 86486 7635 RC0001 | 403,229,000 | 468,680,000 |
| 6 | Hydro One Lake Erie Link Management Inc | 87892 1519 RC0001 | 4,990,000 | 0 |
| 7 | Hydro One Lake Erie Link Company Inc. | 87560 6519 RC0001 | 18,000 | 0 |
| 8 | Hydro One B2M LP Inc. | 81838 2046 RC0001 | 1 | 0 |
| 9 | B2M GP Inc. | 81838 1840 RC0001 | 999 | 0 |
| 10 | Hydro One B2M Holdings Inc. | 82217 7531 RC0001 | 100 | 0 |
| 11 | 1908872 Ontario Inc. | 82581 6838 RC0001 | 1 | 0 |
| 12 | 1908873 Ontario Inc. | 83392 0978 RC0001 | 1 | 0 |
| 13 | 1893080 Ontario Inc. | 82217 7333 RC0001 | 2 | 0 |
| | | **Total** | 450 33,431,225,104 | 550 6,702,002,000 |

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511

Canada

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**SCHEDULE 546**

# *CORPORATIONS INFORMATION ACT* ANNUAL RETURN FOR ONTARIO CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

## Part 1 – Identification

**100** Corporation's name (exactly as shown on the MGS public record)
Hydro One Remote Communities Inc.

| Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent | **110** Date of incorporation or amalgamation, whichever is the most recent | Year Month Day | **120** Ontario Corporation No. |
|---|---|---|---|
| **Ontario** | | 1998-08-18 | 1310735 |

## Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

**200** Care of (if applicable)

| **210** Street number | **220** Street name/Rural route/Lot and Concession number | **230** Suite number |
|---|---|---|
| 483 | Bay Street 8th Floor | |

**240** Additional address information if applicable (line 220 must be completed first)
South Tower

| **250** Municipality (e.g., city, town) | **260** Province/state | **270** Country | **280** Postal/zip code |
|---|---|---|---|
| Toronto | ON | CA | M5G 2P5 |

## Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

**300** [ 1 ] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

## Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

**450** BARAGETTI (Last name) **451** GIOVANNA (First name)

**454** ____________________, (Middle name(s))

**460** [ 3 ] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

**Complete the applicable parts to report changes in the information recorded on the MGS public record.**

## Part 5 – Mailing address

500 [ ] Please enter one of the following numbers in this box:

1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | 530 Street name/Rural route/Lot and Concession number | 540 Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | 570 Province/state | 580 Country | 590 Postal/zip code

## Part 6 – Language of preference

600 [ ] Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

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**SCHEDULE 550**

# ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return.*
- File this schedule with the *T2 Corporation Income Tax Return.*

## Part 1 – Corporate information

| 110 Name of person to contact for more information | 120 Telephone number including area code |
|---|---|
| SELMA YAM | (416) 345-6827 |

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

## Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 9,723,581

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \textbf{ minus } \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \textbf{ minus } \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

| | A<br>Name of university, college, or other eligible educational institution<br>**400** | B<br>Name of qualifying co-operative education program<br>**405** |
|---|---|---|
| 1. | Carelton | Mechanical Engineering |
| 2. | Carelton | Mechanical Engineering |
| 3. | Toronto | Mechanical Engineering |
| 4. | Toronto | Mechanical Engineering |
| 5. | | |

| | C<br>Name of student<br>**410** | D<br>Start date of WP<br>(see note 1 below)<br>**430** | E<br>End date of WP<br>(see note 2 below)<br>**435** |
|---|---|---|---|
| 1. | [redacted] | 2013-05-06 | 2013-08-31 |
| 2. | | 2013-09-01 | 2013-12-31 |
| 3. | | 2013-01-01 | 2013-04-30 |
| 4. | | 2013-05-07 | 2013-08-22 |
| 5. | | | |

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

## Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

| | F1<br>Eligible expenditures before March 27, 2009 (see note 1 below)<br>450 | Eligible percentage before March 27, 2009 (from line 310 in Part 3) | F2<br>Eligible expenditures after March 26, 2009 (see note 1 below)<br>452 | Eligible percentage after March 26, 2009 (from line 310a in Part 3) | X<br>Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below) | Y<br>Total number of consecutive weeks of the student's WP (see note 3 below) |
|---|---|---|---|---|---|---|
| 1. | | 10.000 % | 17,739 | 25.000 % | | 17 |
| 2. | | 10.000 % | 17,739 | 25.000 % | | 17 |
| 3. | | 10.000 % | 22,861 | 25.000 % | | 16 |
| 4. | | 10.000 % | 22,861 | 25.000 % | | 14 |
| 5. | | 10.000 % | | 25.000 % | | |

| | G<br>Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below)<br>460 | H<br>Maximum CETC per WP (see note 3 below)<br>462 | I<br>CETC on eligible expenditures (column G or H, whichever is less)<br>470 | J<br>CETC on repayment of government assistance (see note 4 below)<br>480 | K<br>CETC for each WP (column I or column J)<br>490 |
|---|---|---|---|---|---|
| 1. | 4,435 | 3,000 | 3,000 | | 3,000 |
| 2. | 4,435 | 3,000 | 3,000 | | 3,000 |
| 3. | 5,715 | 3,000 | 3,000 | | 3,000 |
| 4. | 5,715 | 3,000 | 3,000 | | 3,000 |
| 5. | | | | | |

**Ontario co-operative education tax credit** (total of amounts in column K) 500 12,000 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = . . . . . . . . . . . . . . . . . . . . . . ________ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 552**

# ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act.*
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return.*
- File this schedule with your *T2 Corporation Income Tax Return.*

## Part 1 – Corporate information (please print)

| 110 Name of person to contact for more information | 120 Telephone number including area code |
|---|---|
| SELMA YAM | (416) 345-6827 |

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

## Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 9,723,581

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[ 5\,\% \times \frac{(\text{amount on line 300} \text{ minus } 400{,}000)}{200{,}000} \right]$$

**Specified percentage** . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[ 10\,\% \times \frac{(\text{amount on line 300} \text{ minus } 400{,}000)}{200{,}000} \right]$$

**Specified percentage** . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

| | A<br>Trade code<br>**400** | B<br>Apprenticeship program/ trade name<br>**405** | C<br>Name of apprentice<br>**410** |
|---|---|---|---|
| 1. | 310t | Truck And Coach Technician | [redacted] |
| 2. | 310t | Truck And Coach Technician | [redacted] |
| 3. | 310t | Truck And Coach Technician | [redacted] |
| 4. | 310t | Truck And Coach Technician | [redacted] |
| 5. | 434a | Powerline Technician | [redacted] |
| 6. | 434a | Powerline Technician | [redacted] |
| 7. | | | |

| | D<br>Original contract or training agreement number<br>**420** | E<br>Original registration date of apprenticeship contract or training agreement (see note 1 below)<br>**425** | F<br>Start date of employment as an apprentice in the tax year (see note 2 below)<br>**430** | G<br>End date of employment as an apprentice in the tax year (see note 3 below)<br>**435** |
|---|---|---|---|---|
| 1. | [redacted] | 2009-01-05 | 2013-01-01 | 2013-01-05 |
| 2. | [redacted] | 2009-08-17 | 2013-01-02 | 2013-03-14 |
| 3. | [redacted] | 2011-05-30 | 2013-10-28 | 2013-12-19 |
| 4. | [redacted] | 2010-07-05 | 2013-03-06 | 2013-09-27 |
| 5. | [redacted] | 2010-05-03 | 2013-07-22 | 2013-12-31 |
| 6. | [redacted] | 2011-03-28 | 2013-01-21 | 2013-07-19 |

| | D<br>Original contract or training agreement number<br>420 | E<br>Original registration date of apprenticeship contract or training agreement (see note 1 below)<br>425 | F<br>Start date of employment as an apprentice in the tax year (see note 2 below)<br>430 | G<br>End date of employment as an apprentice in the tax year (see note 3 below)<br>435 |
|---|---|---|---|---|
| 7. | | | | |

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

## Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

| | H1<br>Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below)<br>441 | H2<br>Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below)<br>442 | H3<br>Number of days employed as an apprentice in the tax year (column H1 **plus** column H2)<br>440 | I<br>Maximum credit amount for the tax year (see note 2 below)<br>445 |
|---|---|---|---|---|
| 1. | | 5 | 5 | 137 |
| 2. | | 72 | 72 | 1,973 |
| 3. | | 53 | 53 | 1,452 |
| 4. | | 206 | 206 | 5,644 |
| 5. | | 163 | 163 | 4,466 |
| 6. | | 180 | 180 | 4,932 |
| 7. | | | | |

| | J1<br>Eligible expenditures before March 27, 2009 (see note 3 below)<br>451 | J2<br>Eligible expenditures after March 26, 2009 (see note 3 below)<br>452 | J3<br>Eligible expenditures for the tax year (column J1 **plus** column J2)<br>450 | K<br>Eligible expenditures **multiplied** by specified percentage (see note 4 below)<br>460 |
|---|---|---|---|---|
| 1. | | 93,336 | 93,336 | 32,668 |
| 2. | | 92,676 | 92,676 | 32,437 |
| 3. | | 64,434 | 64,434 | 22,552 |
| 4. | | 89,190 | 89,190 | 31,217 |
| 5. | | 103,175 | 103,175 | 36,111 |
| 6. | | 93,143 | 93,143 | 32,600 |
| 7. | | | | |

| | L<br>ATTC on eligible expenditures (lesser of columns I and K)<br>470 | M<br>ATTC on repayment of government assistance (see note 5 below)<br>480 | N<br>ATTC for each apprentice (column L or column M, whichever applies)<br>490 |
|---|---|---|---|
| 1. | 137 | | 137 |
| 2. | 1,973 | | 1,973 |
| 3. | 1,452 | | 1,452 |
| 4. | 5,644 | | 5,644 |
| 5. | 4,466 | | 4,466 |
| 6. | 4,932 | | 4,932 |
| 7. | | | |

**Ontario apprenticeship training tax credit** (total of amounts in column N) 500 18,604 O or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______________ x percentage on line 170 in Part 1 ________ % = . . . . . . . . . . . . . . . . ______________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

200

Canada Revenue Agency / Agence du revenu du Canada

# T2 Corporation Income Tax Return

**055** **Do not use this area**

Filed: 2017-08-28
EB-2017-0051
Exhibit D2-09-01
Attachment 2
Page 1 of 100

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

## Identification

**Business number (BN)** . . . . . . . . . . **001** 87083 6269 RC0001

**Corporation's name**
**002** Hydro One Remote Communities Inc.

**Address of head office**
Has this address changed since the last time we were notified? . . . . . . . . . . . . **010** 1 Yes [X] 2 No [ ]
(If **yes**, complete lines 011 to 018.)
**011** 680 Beaverhall Place
**012**
City: **015** Thunder Bay
Province, territory, or state: **016** ON
Country (other than Canada): **017**
Postal code/Zip code: **018** P7E 6G9

**Mailing address** (if different from head office address)
Has this address changed since the last time we were notified? . . . . . . . . . . . **020** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
**021** c/o Selma Yam
**022** 483 Bay Street 7th Floor
**023** South Tower
City: **025** Toronto
Province, territory, or state: **026** ON
Country (other than Canada): **027**
Postal code/Zip code: **028** M5G 2P5

**Location of books and records** (if different from head office address)
Has the location of books and records changed since the last time we were notified? . . . . . . . . . . . . . . . . . . . . **030** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
**031** 483 Bay Street 7th Floor
**032** South Tower
City: **035** Toronto
Province,territory, or state: **036** ON
Country (other than Canada): **037**
Postal code/Zip code: **038** M5G 2P5

**040** **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . . . . . . . . . . **043** ____ YYYY MM DD

**To which tax year does this return apply?**
Tax year start **060** 2014-01-01 (YYYY MM DD)
Tax year-end **061** 2014-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . . . . . **063** 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired . . . . . . . . . . . . . **065** ____ YYYY MM DD

**Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)?** . . . . . . . . . . . . **066** 1 Yes [ ] 2 No [X]

**Is the corporation a professional corporation that is a member of a partnership?** . . . . . . . . . . . . . . . . . **067** 1 Yes [ ] 2 No [X]

**Is this the first year of filing after:**
Incorporation? . . . . . . . . . . . . . . . **070** 1 Yes [ ] 2 No [X]
Amalgamation? . . . . . . . . . . . . . . . **071** 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . . **072** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . **076** 1 Yes [ ] 2 No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . . **078** 1 Yes [ ] 2 No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . **079** ____

**Is the corporation a resident of Canada?**
**080** 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
**081** ____

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . **082** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**
**085**
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

**Do not use this area**
**095** **096**

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| Is the corporation an associated CCPC? | 160 | X | 23 |
| Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders who own voting shares? | 151 | | 19 |
| Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | X | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | X | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership account number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation own any shares in one or more foreign affiliates in the tax year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*? | 170 | | 29 |
| Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | X | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | ——— |
| Does the corporation earn income from one or more Internet webpages or websites? | 180 | X | 88 |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine? | 202 | | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | | 3 |
| Is the corporation claiming any type of losses? | 204 | X | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | X | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | | 6 |
| i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440? | 207 | | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any property that is eligible capital property? | 210 | | 10 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)? | 213 | | 13 |
| Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits? | 221 | | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | X | 31 |
| Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | | 33/34/35 |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | | ——— |
| Is the corporation claiming a surtax credit? | 237 | | 37 |
| Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II - Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit refund? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit refund? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments – continued from page 2

| | | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates in the tax year? | 271 | | T1134 |
| Did the corporation own specified foreign property in the year with a cost amount over $100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | 262 | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| | | | |
|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | 1 Yes | 2 No X |
| Is the corporation inactive? | 280 | 1 Yes | 2 No X |

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

| | | | |
|---|---|---|---|
| 284 | Electricity generation and distribution | 285 | 100.000 % |
| 286 | | 287 | % |
| 288 | | 289 | % |

| | | | |
|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | 1 Yes | 2 No X |
| Did the corporation emigrate from Canada during the tax year? | 292 | 1 Yes | 2 No X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | 1 Yes | 2 No |
| If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible | 294 | YYYY MM DD | |
| If the corporation's major business activity is construction, did you have any subcontractors during the tax year? | 295 | 1 Yes | 2 No |

## Taxable income

| | | | | |
|---|---|---|---|---|
| Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. | 300 | | -2,858,863 | A |
| **Deduct:** Charitable donations from Schedule 2 | 311 | | | |
| Gifts to Canada, a province, or a territory from Schedule 2 | 312 | | | |
| Cultural gifts from Schedule 2 | 313 | | | |
| Ecological gifts from Schedule 2 | 314 | | | |
| Gifts of medicine from Schedule 2 | 315 | | | |
| Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | | | |
| Part VI.1 tax deduction* | 325 | | | |
| Non-capital losses of previous tax years from Schedule 4 | 331 | | | |
| Net capital losses of previous tax years from Schedule 4 | 332 | | | |
| Restricted farm losses of previous tax years from Schedule 4 | 333 | | | |
| Farm losses of previous tax years from Schedule 4 | 334 | | | |
| Limited partnership losses of previous tax years from Schedule 4 | 335 | | | |
| Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | |
| Prospector's and grubstaker's shares | 350 | | | |
| Subtotal | | | | B |
| Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | | C |
| **Add:** Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | 355 | | | D |
| **Taxable income** (amount C **plus** amount D) | 360 | | | |
| Income exempt under paragraph 149(1)(t) | 370 | | | |
| **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | | Z |

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

| | | | |
|---|---|---|---|
| Income from active business carried on in Canada from Schedule 7 | 400 | | A |
| Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax | 405 | | B |
| Business limit (see notes 1 and 2 below) | 410 | | C |

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction:**

Amount C ____ x (415 *** ____ / 11,250) D = ____ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 ____ F

**Small business deduction**

Amount A, B, C, or F, whichever is the least ____ x 17 % = 430 ____ G

Enter amount G on line I on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | A |
| Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 | | B | | |
| Amount QQ from Part 13 of Schedule 27 | | C | | |
| Personal service business income | 432 | D | | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | E | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | F | | |
| Aggregate investment income from line 440 on page 6* | | G | | |
| Subtotal (**add** amounts B to G) | | | | H |
| Amount A **minus** amount H (if negative, enter "0") | | | | I |
| **General tax reduction for Canadian-controlled private corporations** – Amount I **multiplied** by 13 % | | | | J |

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | K |
| Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 | | L | | |
| Amount QQ from Part 13 of Schedule 27 | | M | | |
| Personal service business income | 434 | N | | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | O | | |
| Subtotal (**add** amounts L to O) | | | | P |
| Amount K **minus** amount P (if negative, enter "0") | | | | Q |
| **General tax reduction** – Amount Q **multiplied** by 13 % | | | | R |

Enter amount R on line 639 on page 7.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

| | | | | | |
|---|---|---|---|---|---|
| Aggregate investment income from Schedule 7 . . . . . . . . **440** | | x 26 2 / 3 % = | . . . . . . . . . . . . . . . . | | A |
| Foreign non-business income tax credit from line 632 on page 7 . . . . . . . . . . . . . . . . . . . . . . | | | | B | |
| **Deduct:** | | | | | |
| Foreign investment income from Schedule 7 . . . . . . . . . . **445** | | x 9 1 / 3 % = | | C | |
| | | (if negative, enter "0") | | | D |
| Amount A **minus** amount D (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | | | | | E |
| Taxable income from line 360 on page 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | | | | F | |
| **Deduct:** | | | | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | | | G | | |
| Foreign non-business income tax credit from line 632 on page 7 . . . | x 100 / 35 = | | H | | |
| Foreign business income tax credit from line 636 on page 7 . . . . . . . . . . . . . | x 4 = | | I | | |
| | Subtotal | | | J | |
| | | | | K | |
| | | | x 26 2 / 3 % = | | L |
| Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . . . . . . . . . . . . . . . . . . . | | | | | M |
| **Refundable portion of Part I tax** – Amount E, L, or M, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **450** | | | | | N |

## Refundable dividend tax on hand

| | | | |
|---|---|---|---|
| Refundable dividend tax on hand at the end of the previous tax year . . . . . . . . . . . . . . . . . **460** | | | |
| **Deduct:** Dividend refund for the previous tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **465** | | | |
| | | | O |
| **Add** the total of: | | | |
| Refundable portion of Part I tax from line 450 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | | P | |
| Total Part IV tax payable from Schedule 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | | Q | |
| Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . . . . . . . . . . . . . . . . . . . . **480** | | | |
| | | | R |
| **Refundable dividend tax on hand at the end of the tax year** – Amount O **plus** amount R . . . . . . . . . . . . . . . . . . . . **485** | | | |

## Dividend refund

**Private and subject corporations at the time taxable dividends were paid in the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . . . . . . | | x 1 / 3 = | | S |
| Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | | | | T |
| **Dividend refund** – Amount S or T, whichever is less . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | | | | U |

Enter amount U on line 784 on page 8.

## Part I tax

**Base amount Part I tax** – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % . . . **550** ____ A

**Recapture of investment tax credit from Schedule 31** . . . **602** ____ B

**Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income**
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . ____ C

Taxable income from line 360 on page 3 . . . ____ D

**Deduct:**

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . ____ E

Net amount (amount D **minus** amount E) . . . ____ ____ F

**Refundable tax on CCPC's investment income** – 6 2 / 3 % of whichever is less: amount C or amount F . . . **604** ____ G

Subtotal (**add** amounts A, B, and G) ____ H

**Deduct:**

| | | | |
|---|---|---|---|
| Small business deduction from line 430 on page 4 | | | I |
| Federal tax abatement | **608** | | |
| Manufacturing and processing profits deduction from Schedule 27 | **616** | | |
| Investment corporation deduction | **620** | | |
| Taxed capital gains **624** ____ | | | |
| Additional deduction – credit unions from Schedule 17 | **628** | | |
| Federal foreign non-business income tax credit from Schedule 21 | **632** | | |
| Federal foreign business income tax credit from Schedule 21 | **636** | | |
| General tax reduction for CCPCs from amount J on page 5 | **638** | | |
| General tax reduction from amount R on page 5 | **639** | | |
| Federal logging tax credit from Schedule 21 | **640** | | |
| Eligible Canadian bank deduction under section 125.21 | **641** | | |
| Federal qualifying environmental trust tax credit | **648** | | |
| Investment tax credit from Schedule 31 | **652** | | |
| Subtotal | | | J |

**Part I tax payable** – Amount H **minus** amount J . . . ____ K
Enter amount K on line 700 on page 8.

## Summary of tax and credits

**Federal tax**

| | | |
|---|---|---|
| Part I tax payable from amount K on page 7 | 700 | |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | | |
|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | |
| Provincial tax on large corporations (Nova Scotia Schedule 342) | 765 | |

(The Nova Scotia tax on large corporations is eliminated effective July 1, 2012.)

Total provincial or territorial tax ▶

Total tax payable 770 ______ A

**Deduct other credits:**

| | | |
|---|---|---|
| Investment tax credit refund from Schedule 31 | 780 | |
| Dividend refund from amount U on page 6 | 784 | |
| Federal capital gains refund from Schedule 18 | 788 | |
| Federal qualifying environmental trust tax credit refund | 792 | |
| Canadian film or video production tax credit refund (Form T1131) | 796 | |
| Film or video production services tax credit refund (Form T1177) | 797 | |
| Tax withheld at source | 800 | |
| Total payments on which tax has been withheld | 801 | |
| Provincial and territorial capital gains refund from Schedule 18 | 808 | |
| Provincial and territorial refundable tax credits from Schedule 5 | 812 | 55,644 |
| Tax instalments paid | 840 | |
| Total credits | 890 | 55,644 |

Total credits 890 55,644 ▶ 55,644 B

Refund code 894 2 Overpayment 55,644 ◀ Balance (amount A **minus** amount B) -55,644

If the result is positive, you have a **balance unpaid**. If the result is negative, you have an **overpayment**. Enter the amount on whichever line applies. Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . .

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

Enclosed payment 898

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

## Certification

I, 950 BARAGETTI (Last name (print)) 951 GIOVANNA (First name (print)) 954 Vice President, Corporate Tax (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2015-06-29 — Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (416) 345-6778 — Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No ☒

958 SELMA YAM — Name (print) 959 (416) 345-6827 — Telephone number

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

# HYDRO ONE REMOTE COMMUNITIES INC.

## FINANCIAL STATEMENTS

## DECEMBER 31, 2014

**HYDRO ONE REMOTE COMMUNITIES INC.**
**INDEPENDENT AUDITORS' REPORT**

To Directors of Hydro One Remote Communities Inc.

We have audited the accompanying financial statements of Hydro One Remote Communities Inc., which comprise the balance sheet as at December 31, 2014, the statements of operations and comprehensive income, changes in shareholder's deficit and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these 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 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 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 Hydro One Remote Communities Inc. as at December 31, 2014, and its results of operations and its cash flows for the year then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
March 24, 2015

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**
**For the years ended December 31, 2014 and 2013**

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Revenues** *(Note 15)* | 52,130 | 50,035 |
| **Costs** | | |
| Operation, maintenance and administration *(Note 15)* | 20,069 | 19,645 |
| Fuel used for electric generation | 25,869 | 25,568 |
| Depreciation and amortization *(Note 4)* | 4,623 | 4,809 |
| | 50,561 | 50,022 |
| **Income (loss) before financing charges and recovery of payments in lieu of corporate income taxes** | 1,569 | 13 |
| Financing charges *(Notes 5, 15)* | 1,559 | 1,104 |
| **Income before recovery of payments in lieu of corporate income taxes** | 10 | (1,091) |
| Provision for (recovery of) payments in lieu of corporate income taxes *(Notes 6, 15)* | 10 | (1,091) |
| **Net income** | – | – |
| Other comprehensive income | 13 | 13 |
| **Comprehensive income** | 13 | 13 |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS**
**At December 31, 2014 and 2013**

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Accounts receivable (net of allowance for doubtful accounts – $145; 2013 – $296) *(Notes 7, 15)* | 4,454 | 4,995 |
| Regulatory assets *(Note 9)* | 1,301 | 2,427 |
| Fuel, materials and supplies | 2,092 | 1,736 |
| Deferred income tax assets *(Note 6)* | 120 | 108 |
| Income tax receivable *(Notes 6, 15)* | 2,683 | 2,697 |
| | 10,650 | 11,963 |
| Property, plant and equipment *(Note 8)*: | | |
| Property, plant and equipment in service | 63,601 | 58,905 |
| Less: accumulated depreciation | 24,588 | 23,256 |
| | 39,013 | 35,649 |
| Construction in progress | 2,138 | 3,473 |
| Future use components and spares | 1,767 | 1,650 |
| | 42,918 | 40,772 |
| Other long-term assets: | | |
| Regulatory assets *(Note 9)* | 18,283 | 15,923 |
| Deferred income tax assets *(Note 6)* | 4,213 | 4,239 |
| Deferred debt issuance costs *(Note 10)* | 183 | 124 |
| Long-term accounts receivable (net of allowance for doubtful accounts – $159; 2013 – $0) *(Note 7)* | 1,250 | 674 |
| | 23,929 | 20,960 |
| **Total assets** | 77,497 | 73,695 |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS (continued)**
**At December 31, 2014 and 2013**

| *December 31 (thousands of Canadian dollars, except number of shares)* | **2014** | **2013** |
|---|---|---|
| **Liabilities** | | |
| Current liabilities: | | |
| Inter-company demand facility *(Notes 11, 15)* | 6,806 | 18,031 |
| Accounts payable | 876 | 703 |
| Accrued liabilities *(Notes 12, 13)* | 8,936 | 4,954 |
| Accrued interest *(Note 15)* | 172 | 142 |
| Regulatory liabilities *(Note 9)* | 120 | 109 |
| | 16,910 | 23,939 |
| Long-term debt *(Notes 10, 11, 15)* | 33,000 | 23,000 |
| Other long-term liabilities: | | |
| Post-retirement and post-employment benefit liability *(Note 12)* | 12,862 | 12,088 |
| Regulatory liabilities *(Note 9)* | 4,213 | 4,238 |
| Environmental liabilities *(Note 13)* | 11,068 | 10,999 |
| | 28,143 | 27,325 |
| **Total liabilities** | 78,053 | 74,264 |
| *Contingencies and commitments (Notes 17, 18)* | | |
| **Shareholder's deficit** | | |
| Common shares (authorized: unlimited; issued: 2) *(Note 14)* | – | – |
| Accumulated other comprehensive loss | (556) | (569) |
| **Total shareholder's deficit** | (556) | (569) |
| **Total liabilities and shareholder's deficit** | 77,497 | 73,695 |

*See accompanying notes to Financial Statements.*

On behalf of the Board of Directors:

Carmine Marcello
Chair

Lee Ann Cameron
Director

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CHANGES IN SHAREHOLDER'S DEFICIT**
**For the years ended December 31, 2014 and 2013**

| *Year ended December 31, 2014*<br>*(thousands of Canadian dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2014 | – | (569) | (569) |
| Other comprehensive income | – | 13 | 13 |
| **December 31, 2014** | – | (556) | (556) |

| *Year ended December 31, 2013*<br>*(thousands of Canadian dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2013 | – | (582) | (582) |
| Other comprehensive income | – | 13 | 13 |
| **December 31, 2013** | – | (569) | (569) |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CASH FLOWS**
**For the years ended December 31, 2014 and 2013**

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Operating activities** | | |
| Net income | – | – |
| Environmental expenditures | (1,598) | (1,656) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (excluding removal costs) | 4,193 | 4,220 |
| Regulatory assets and liabilities | (2,594) | (1,126) |
| Amortization of hedging losses | 13 | 13 |
| Amortization of deferred debt costs and debt discounts | 3 | 3 |
| Changes in non-cash balances related to operations *(Note 16)* | 6,007 | (2,773) |
| **Net cash from (used in) operating activities** | 6,024 | (1,319) |
| **Financing activities** | | |
| Long-term debt issued | 10,000 | – |
| Other | (60) | – |
| **Net cash from financing activities** | 9,940 | – |
| **Investing activities** | | |
| Capital expenditures | (4,634) | (5,427) |
| Proceeds on disposition of property, plant and equipment | 12 | 4 |
| Future use assets | (117) | (77) |
| **Net cash used in investing activities** | (4,739) | (5,500) |
| **Net change in inter-company demand facility** | 11,225 | (6,819) |
| Inter-company demand facility, beginning of year | (18,031) | (11,212) |
| **Inter-company demand facility, end of year** | (6,806) | (18,031) |

*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 Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario), and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The Company uses a cost recovery model applied to achieve breakeven net income and the financial statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2014 have been prepared and are publicly available.

Hydro One Remote Communities 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. No such events or transactions were identified.

### Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairment, contingencies, unbilled revenue, allowance for doubtful accounts 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

In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 distribution rates, seeking approval for a rate increase of approximately 0.48%. On March 13, 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.

In 2012, Hydro One Remote Communities filed a cost-of-service application for 2013 distribution rates. The application requested an increase of 3.45% to customer rates for generation and distribution and an increase of approximately $7 million to annual Rural and Remote Rate Protection (RRRP). In 2013, the OEB approved the proposed rate increase and annual RRRP of approximately $32 million.

### Regulatory Accounting

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

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of the recovery of / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in RRRP amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

### Revenue Recognition

Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues attributable to the generation and 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 RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

### Accounts Receivable and Allowance for Doubtful Accounts

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

Long-term accounts receivable are recorded at their invoiced amount and represent amounts due from specified First Nations. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. Provision for uncollectible amounts for this component is set at the inception of the balance and is maintained until settlement of those amounts. The provision for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts

receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

**Corporate Income Taxes**

Under the *Electricity Act, 1998*, Hydro One Remote Communities is required to make (recover) PILs to (from) 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 recovery of or 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 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.

**Inter-company Demand Facility**

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and

withdrawals made by the Company to and from the pooled cash 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%.

**Fuel, Materials and Supplies**

Fuel is used in the generation of electricity. 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

***Generation***

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

***Distribution***

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

***Administration and Service***

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

**Capitalized Financing Costs**

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 in Progress**

Construction 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

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category.

The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 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 |
|---|---|---|---|
| Generation | 22 years | 3% – 7% | 5% |
| Distribution | 48 years | 1% – 7% | 2% |
| Administration and service | 45 years | 2% – 20% | 4% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 assets where no asset retirement obligation 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 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. As at December 31, 2014, no asset impairment had been recorded.

### 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 Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents OCI and net income 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.

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 11 – Fair Value of Financial Instruments and Risk Management.

Transaction costs associated with financial assets and liabilities that are designated as held-for-trading are recognized immediately in results of operations. All financial instrument transactions are recorded at trade date.

### Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2014. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

### Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's 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 plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets 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 all 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, including Hydro One Remote Communities, but not including Hydro One Brampton Inc and Norfolk Power Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit 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*

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of the these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for

purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's 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 accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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 Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its 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. 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 Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement 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 Remote Communities records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

## 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 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 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 financial statements.

## 4. DEPRECIATION AND AMORTIZATION

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Depreciation of property, plant and equipment | 2,594 | 2,564 |
| Asset removal costs | 430 | 589 |
| Amortization of regulatory assets | 1,599 | 1,656 |
| | 4,623 | 4,809 |

## 5. FINANCING CHARGES

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Interest on long-term debt | 1,477 | 1,237 |
| Interest on inter-company demand facility | 187 | 216 |
| Amortization of hedging losses | 13 | 13 |
| Other | 28 | 14 |
| Less: Interest capitalized on construction in progress | (146) | (376) |
| | 1,559 | 1,104 |

## 6. PROVISION FOR PILS

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 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Income (loss) before provision for (recovery of) PILs | 10 | (1,091) |
| Canadian Federal and Ontario statutory income tax rate | 26.50% | 26.50% |
| Provision for (recovery of) PILs at statutory rate | 3 | (289) |
| | | |
| Increase (decrease) resulting from: | | |
| | | |
| Net temporary differences included in amounts charged to customers: | | |
| RRPR variance account | (687) | (318) |
| Environmental expenditures | (424) | (439) |
| Pension contribution in excess of pension expense | (132) | (90) |
| Overheads capitalized for accounting but deducted for tax purposes | (93) | (82) |
| Interest capitalized for accounting but deducted for tax purposes | (39) | (100) |
| Losses carryforward | 846 | – |
| Depreciation and amortization in excess of capital cost allowance | 338 | 469 |
| Post-retirement and post-employment benefit expense in excess of cash payments | 189 | 135 |
| Other | – | 56 |
| Net temporary differences | (2) | (369) |
| Prior year adjustments | 10 | (332) |
| Rate difference on loss carryback | – | (110) |
| Other permanent differences | (1) | 9 |
| Total provision for (recovery of) PILs | 10 | (1,091) |
| | | |
| Current provision for (recovery of) PILs | 10 | (1,091) |
| Deferred provision for (recovery of) PILs | – | – |
| Total provision for (recovery of) PILs | 10 | (1,091) |
| | | |
| Effective income tax rate | 100% | 100% |

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2014, the amount receivable from the OEFC was $2,683 thousand (2013 – $2,697 thousand).

### Deferred Income Tax Assets

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, 2014 and 2013, deferred income tax assets and liabilities consisted of the following:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Deferred income tax assets** | | |
| Post-retirement and post-employment benefits expense in excess of cash payments | 4,762 | 4,466 |
| Environmental expenditures | 4,459 | 4,840 |
| Depreciation and amortization in excess of capital cost allowance | 1,231 | 1,845 |
| Non capital losses | 1,183 | – |
| Regulatory amounts not recognized for tax | (7,060) | (6,615) |
| Other | (242) | (189) |
| Total deferred income tax assets | 4,333 | 4,347 |
| Less: current portion | 120 | 108 |
| | 4,213 | 4,239 |

During 2014 and 2013, there was no change in the rate applicable to future taxes.

## 7. ACCOUNTS RECEIVABLE

| *December 31 (thousands of Canadian dollars)* | Current accounts receivable | Long-term accounts receivable | Total |
|---|---|---|---|
| **2014** | | | |
| Accounts receivable – billed | 3,214 | 1,409 | 4,623 |
| Accounts receivable – unbilled | 1,385 | – | 1,385 |
| Accounts receivable, gross | 4,599 | 1,409 | 6,008 |
| Allowance for doubtful accounts | (145) | (159) | (304) |
| Accounts receivable, net | 4,454 | 1,250 | 5,704 |
| | | | |
| **2013** | | | |
| Accounts receivable – billed | 3,887 | 674 | 4,561 |
| Accounts receivable – unbilled | 1,404 | – | 1,404 |
| Accounts receivable, gross | 5,291 | 674 | 5,965 |
| Allowance for doubtful accounts | (296) | – | (296) |
| Accounts receivable, net | 4,995 | 674 | 5,669 |

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2014 and 2013:

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Allowance for doubtful accounts – January 1 | (296) | (302) |
| Write-offs | 77 | 95 |
| Adjustments to allowance for doubtful accounts | (85) | (89) |
| Allowance for doubtful accounts – December 31 | (304) | (296) |

## 8. PROPERTY, PLANT AND EQUIPMENT

| *December 31 (thousands of Canadian dollars)* | Costs | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| **2014** | | | | |
| Generation | 44,770 | 20,385 | 1,742 | 26,127 |
| Distribution | 9,488 | 1,906 | 99 | 7,681 |
| Administration and Service | 11,110 | 2,297 | 297 | 9,110 |
| | 65,368 | 24,588 | 2,138 | 42,918 |
| **2013** | | | | |
| Generation | 41,616 | 19,517 | 2,716 | 24,815 |
| Distribution | 8,394 | 1,748 | 596 | 7,242 |
| Administration and Service | 10,545 | 1,991 | 161 | 8,715 |
| | 60,555 | 23,256 | 3,473 | 40,772 |

Financing charges capitalized on property, plant and equipment under construction were $146 thousand in 2014 (2013 – $376 thousand).

## 9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Regulatory assets:** | | |
| Environmental | 12,369 | 13,426 |
| RRPR variance account | 4,578 | 1,985 |
| Post-retirement and post-employment benefits | 2,637 | 2,939 |
| Total regulatory assets | 19,584 | 18,350 |
| Less: current portion | 1,301 | 2,427 |
| | 18,283 | 15,923 |
| **Regulatory liabilities:** | | |
| Deferred income tax regulatory liability | 4,333 | 4,347 |
| Total regulatory liabilities | 4,333 | 4,347 |
| Less: current portion | 120 | 109 |
| | 4,213 | 4,238 |

### Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. Management considers it probable that such expenditures will be recovered in the future through the rate-setting process, and as such, the Company has recorded an equivalent amount as a regulatory asset. In 2014, this regulatory asset increased by $180 thousand (2013 – $2,872 thousand) to reflect related changes in the Company's environmental liabilities. 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 Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2014 operation, maintenance and administration expenses would have been higher by $180 thousand (2013 – $2,872 thousand). In addition, 2014 amortization expense would have been lower by $1,598 thousand (2013 – $1,656 thousand), and 2014 financing charges would have been higher by $361 thousand (2013 – $330 thousand).

**RRPR Variance Account**

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2014, the Company has recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of net RRRP amounts received. At December 31, 2013, net RRRP amounts received were also lower than amounts required to achieve breakeven net income, and as such, a regulatory asset was also recognized. In the absence of rate-regulated accounting, 2014 revenue would have been lower by $2,593 thousand (2013 – $1,198 thousand).

**Post-Retirement and Post-Employment Benefits**

The Company 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 $302 thousand (2013 – $205 thousand).

**Deferred Income Tax Regulatory 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 recovery of PILs would have been lower by approximately $2 thousand (2013 – $367 thousand).

## 10. LONG-TERM DEBT

Long-term debt totalling $33,000 thousand is payable to Hydro One and consists of a $23,000 thousand note maturing in 2036 and a $10,000 thousand note maturing in 2044.

The $23,000 thousand note was issued on May 19, 2005, with an interest rate of 5.38% per annum and a maturity date of May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999 in consideration of the purchase price of Hydro One Remote Communities' net assets. On issuance of this note, $115 thousand of transaction costs and a $31 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

The $10,000 thousand note was issued on June 6, 2014, with an interest rate of 4.19% per annum and a maturity date of June 6, 2044. On issuance of this note, $50 thousand of transaction costs and a $10 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

## 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.

Hydro One Remote Communities 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 Remote Communities 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 Company's 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 Hierarchy**

The fair value hierarchy of financial assets and liabilities at December 31, 2014 and 2013 are as follows:

| *December 31, 2014 (thousands of Canadian dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 6,806 | 6,806 | 6,806 | – | – |
| Long-term debt | 33,000 | 39,226 | – | 39,226 | – |
| | 39,806 | 46,032 | 6,806 | 39,226 | – |

| *December 31, 2013 (thousands of Canadian dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 18,031 | 18,031 | 18,031 | – | – |
| Long-term debt | 23,000 | 25,450 | – | 25,450 | – |
| | 41,031 | 43,481 | 18,031 | 25,450 | – |

The fair value 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 foreign exchange risk is currently not significant, although Hydro One could in the future decide to issue and allocate foreign currency-denominated debt to the Company, along with an allocation of the resulting foreign exchange gains and losses. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%.

***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 Remote Communities 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 Company's total provision for bad debts was $304 thousand (2013 – $296 thousand). 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 36% of the Company's current accounts receivable were aged more than 60 days (2013 – 47%). Sufficient allowances have been recorded to reflect the risk of potential credit losses.

***Liquidity Risk***

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities 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 $9,812 thousand (2013 – $5,657 thousand) are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2014, Hydro One Remote Communities had long-term debt in the principal amount of $33,000 thousand (2013 – $23,000 thousand). No long-term debt matures during the next year. Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $1,656 thousand (2013 – $1,237 thousand). Principal repayments and interest payments are summarized by the number of years to maturity in the following table.

| **Years to Maturity** | **Principal Repayments on Long-term Debt** *(thousands of Canadian dollars)* | **Interest Payments** *(thousands of Canadian dollars)* | **Weighted Average Interest Rate** *(%)* |
|---|---|---|---|
| 1 year | – | 1,656 | 5.019 |
| 2 years | – | 1,656 | 5.019 |
| 3 years | – | 1,656 | 5.019 |
| 4 years | – | 1,656 | 5.019 |
| 5 years | – | 1,656 | 5.019 |
| | – | 8,280 | 5.019 |
| 6 – 10 years | – | 8,280 | 5.019 |
| Over 10 years | 33,000 | 22,405 | 5.019 |
| | 33,000 | 38,965 | 5.019 |

## 12. 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. 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 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.

Company and employees' 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, Hydro One Remote Communities charged $941 thousand (2013 – $775 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $272 thousand (2013 – $250 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2014 were $91 thousand (2013 – $264 thousand). In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $302 thousand (2013 – $205 thousand) was recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Accrued liabilities | 346 | 300 |
| Post-retirement and post-employment benefit liability | 12,862 | 12,088 |
| | 13,208 | 12,388 |

## 13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2014 and 2013:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Environmental liabilities, January 1 | 13,426 | 11,880 |
| Interest accretion | 361 | 330 |
| Expenditures | (1,598) | (1,656) |
| Revaluation adjustment | 180 | 2,872 |
| Environmental liabilities, December 31 | 12,369 | 13,426 |
| Less: current portion | 1,301 | 2,427 |
| | 11,068 | 10,999 |

The following table illustrates 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 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Undiscounted environmental liabilities, December 31 | 12,881 | 14,014 |
| Less: discounting accumulated liabilities to present value | 512 | 588 |
| Discounted environmental liabilities, December 31 | 12,369 | 13,426 |

At December 31, 2014, the estimated future environmental expenditures were as follows:

| *(thousands of Canadian dollars)* | |
|---|---|
| 2015 | 1,301 |
| 2016 | 2,619 |
| 2017 | 2,717 |
| 2018 | 1,851 |
| 2019 | 1,657 |
| Thereafter | 2,736 |
| | 12,881 |

The Company records a liability for the estimated future expenditures for the contaminated LAR 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 3.6% to 4.9%, 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.

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $12,881 thousand. These expenditures are expected to be incurred over the period from 2015 to 2020. 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 $180 thousand (2013 – $2,872 thousand).

## 14. SHARE CAPITAL

### Common Shares

The Company has 2 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

### Dividends

The Company has no retained earnings and does not pay dividends under its breakeven business model.

## 15. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities 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 Hydro One Remote Communities because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One Remote Communities are described below.

Hydro One Remote Communities receives amounts for RRRP from the IESO. RRRP amounts received for the year ended December 31, 2014 were $32,259 thousand (2013 – $33,046 thousand). Consistent with its breakeven business model, the Company recognized $34,852 thousand as RRRP revenue in 2014 (2013 – $34,245 thousand). This 2014 revenue exceeded amounts received by $2,593 thousand (2013 – $1,199 thousand) and the RRPR variance account balance was adjusted by this amount.

PILs are paid to or received from the OEFC.

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

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Accounts receivable | 106 | 97 |
| Income tax receivable | 2,683 | 2,697 |

Transactions with 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.

### Hydro One and Subsidiaries

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its other 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 corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2014 revenues include $109 thousand (2013 – $195 thousand) related to the provision of services to Hydro One and its other subsidiaries. 2014 operation, maintenance and administration costs include $2,958 thousand (2013 – $3,475 thousand) related to the purchase of services from Hydro One and its other subsidiaries.

The Company's long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One and its other subsidiaries. Financing charges include interest expense on the long-term debt in the amount of $1,477 thousand (2013 – $1,237 thousand), and interest expense on the inter-company demand facility in the amount of $187 thousand (2013 – $216 thousand). At December 31, 2014, the Company had accrued interest payable to Hydro One totaling $172 thousand (2013 – $142 thousand).

## 16. STATEMENTS OF CASH FLOWS

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

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Accounts receivable | 541 | (802) |
| Materials and supplies | (356) | 443 |
| Income taxes receivable | 14 | (1,108) |
| Long-term accounts receivable | (576) | (256) |
| Accounts payable | 173 | (284) |
| Accrued liabilities | 5,105 | (1,526) |
| Accrued interest | 30 | – |
| Post-retirement and post-employment benefit liability | 1,076 | 760 |
| | 6,007 | (2,773) |
| **Supplementary information:** | | |
| Net interest paid | 1,447 | 1,453 |

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any PILs paid are fully recovered.

## 17. CONTINGENCIES

### Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

### Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One 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, Hydro One paid approximately $1 million (2013 – $2 million) in respect of these consents. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One 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 Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

## 18. COMMITMENTS

### Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years.

During the year ended December 31, 2014, the Company made lease payments totalling $120 thousand (2013 – $1 million). At December 31, 2014, the future minimum lease payments under non-cancellable operating leases were as follows: 2015 – $120 thousand; 2016 – $120 thousand; 2017 – $120 thousand; 2018 – $150 thousand; 2019 – $150 thousand; and thereafter – $450 thousand.

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**SCHEDULE 100**

Form identifier 100

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2014-12-31 |

### Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 10,650,000 | 11,963,000 |
| | Total tangible capital assets | 2008 | + | 67,506,000 | 64,028,000 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 24,588,000 | 23,256,000 |
| | Total intangible capital assets | 2178 | + | | |
| | Total accumulated amortization of intangible capital assets | 2179 | – | | |
| | Total long-term assets | 2589 | + | 23,929,000 | 20,960,000 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 77,497,000 | 73,695,000 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 16,910,000 | 23,939,000 |
| | Total long-term liabilities | 3450 | + | 61,143,000 | 50,325,000 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 78,053,000 | 74,264,000 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | -556,000 | -569,000 |
| | **Total liabilities and shareholder equity** | 3640 | = | 77,497,000 | 73,695,000 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | | |

* Generic item

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**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2014-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | Ontario Hydro Remote Communities Service Company Inc. |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Income statement information** | | | | |
| | Total sales of goods and services | 8089 | + | 52,130,000 | 50,035,000 |
| | Cost of sales | 8518 | – | 25,869,000 | 25,568,000 |
| | **Gross profit/loss** | 8519 | = | 26,261,000 | 24,467,000 |
| | Cost of sales | 8518 | + | 25,869,000 | 25,568,000 |
| | Total operating expenses | 9367 | + | 26,251,000 | 25,558,000 |
| | **Total expenses** (mandatory field) | 9368 | = | 52,120,000 | 51,126,000 |
| | Total revenue (mandatory field) | 8299 | + | 52,130,000 | 50,035,000 |
| | Total expenses (mandatory field) | 9368 | – | 52,120,000 | 51,126,000 |
| | **Net non-farming income** | 9369 | = | 10,000 | -1,091,000 |
| | **Farming income statement information** | | | | |
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | 10,000 | -1,091,000 |
| | **Total other comprehensive income** | 9998 | = | 13,000 | 13,000 |
| | **Extraordinary items and income (linked to Schedule 140)** | | | | |
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | 10,000 | -1,091,000 |
| | Future (deferred) income tax provision | 9995 | – | | |
| | Total – Other comprehensive income | 9998 | + | 13,000 | 13,000 |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 13,000 | 13,000 |

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**Schedule 141**

# Notes checklist

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2014-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Does the accountant have a professional designation? | 095 | X | |
| Is the accountant connected* with the corporation? | 097 | | X |

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

**Note**
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

| Option | No. | |
|---|---|---|
| Completed an auditor's report | 1 | X |
| Completed a review engagement report | 2 | |
| Conducted a compilation engagement | 3 | |

## Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Has the accountant expressed a reservation? | 099 | | X |

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

| Option | No. | |
|---|---|---|
| Prepared the tax return (financial statements prepared by client) | 1 | X |
| Prepared the tax return and the financial information contained therein (financial statements have not been prepared) | 2 | |

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Were notes to the financial statements prepared? | 101 | X | |

If **yes**, complete lines 104 to 107 below:

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Are subsequent events mentioned in the notes? | 104 | | X |
| Is re-evaluation of asset information mentioned in the notes? | 105 | | X |
| Is contingent liability information mentioned in the notes? | 106 | X | |
| Is information regarding commitments mentioned in the notes? | 107 | X | |
| Does the corporation have investments in joint venture(s) or partnership(s)? | 108 | | X |

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income Increase (decrease) | | In OCI Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

## 8. PROPERTY, PLANT AND EQUIPMENT

| *December 31 (thousands of dollars)* | Costs | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| **2013** | | | | |
| Generation | 41,616 | 19,517 | 2,716 | 24,815 |
| Distribution | 8,394 | 1,748 | 596 | 7,242 |
| Administration and Service | 10,545 | 1,991 | 161 | 8,715 |
| | 60,555 | 23,256 | 3,473 | 40,772 |
| **2012** | | | | |
| Generation | 38,803 | 22,056 | 6,764 | 23,511 |
| Distribution | 7,757 | 1,785 | 315 | 6,287 |
| Administration and Service | 9,803 | 1,938 | 171 | 8,036 |
| | 56,363 | 25,779 | 7,250 | 37,834 |

Financing charges capitalized on property, plant and equipment under construction were $376 thousand in 2013 (2012 – $321 thousand).

## 9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

| *December 31 (thousands of dollars)* | 2013 | 2012 |
|---|---|---|
| **Regulatory assets:** | | |
| Environmental | 13,426 | 11,880 |
| Post-retirement and post-employment benefits | 2,939 | 3,144 |
| RRPR variance account | 1,985 | 787 |
| IFRS transition cost variance | – | 72 |
| Total regulatory assets | 18,350 | 15,883 |
| Less: current portion | 2,427 | 1,823 |
| | 15,923 | 14,060 |
| **Regulatory liabilities:** | | |
| Deferred income tax regulatory liability | 4,347 | 4,841 |
| Total regulatory liabilities | 4,347 | 4,841 |
| Less: current portion | 108 | 108 |
| | 4,239 | 4,733 |

### Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. Management considers it probable that such expenditures will be recovered in the future through the rate-setting process, and as such, the Company has recorded an equivalent amount as a regulatory asset. In 2013, this regulatory asset increased by $2,872 thousand (2012 – decreased by $583 thousand) to reflect related changes in the Company's environmental liabilities. 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 Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2013 operation, maintenance and administration expenses would have been higher by $2,872 thousand (2012 – lower by $583 thousand). In addition, 2013 amortization expense would have been lower by $1,656 thousand (2012 – $2,515 thousand), and 2013 financing charges would have been higher by $330 thousand (2012 – $399 thousand).

**Post-Retirement and Post-Employment Benefits**

The Company 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 $205 thousand (2012 – lower by $1,941 thousand).

**RRPR Variance Account**

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2013, the Company has recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of net RRRP amounts received. At December 31, 2012, net RRRP amounts received were also lower than amounts required to achieve breakeven net income, and as such, a regulatory asset was also recognized. In the absence of rate-regulated accounting, 2013 revenue would have been lower by $1,198 thousand (2012 – $3,957 thousand).

**IFRS Transition Costs Variance**

Hydro One Remote Communities recorded an asset for the variance between its one-time incremental costs incurred in its uncompleted transition to IFRS and amounts included in rates in respect of this project. In 2013, the company decided not to seek recovery of this amount from rate payers and it was included in the Statement of Operations.

**Deferred Income Tax Regulatory 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 recovery of PILs would have been lower by approximately $367 thousand (2012 – $771 thousand).

## 10. LONG-TERM DEBT

Long-term debt represents a note payable to Hydro One. The note was issued on May 19, 2005, with a carrying value of $23,000 thousand and interest at a rate of 5.38% per annum. The note matures on May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999 in consideration of the purchase price of Hydro One Remote Communities' net assets.

On issuance of this note, $115 thousand of transaction costs and a $31 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

## 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.

Hydro One Remote Communities 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 Remote Communities 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 Company's 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 Hierarchy**

The fair value hierarchy of financial assets and liabilities at December 31, 2013 and 2012 are as follows:

| *December 31, 2013 (thousands of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 18,031 | 18,031 | 18,031 | – | – |
| Long-term debt | 23,000 | 25,450 | – | 25,450 | – |
| | 41,031 | 43,481 | 18,031 | 25,450 | – |

| *December 31, 2012 (thousands of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 11,212 | 11,212 | 11,212 | – | – |
| Long-term debt | 23,000 | 28,486 | – | 28,486 | – |
| | 34,212 | 39,698 | 11,212 | 28,486 | – |

The fair value 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 foreign exchange risk is currently not significant, although Hydro One could in the future decide to issue and allocate foreign currency-denominated debt to the Company, along with an allocation of the resulting foreign exchange gains and losses. The Company is exposed to fluctuations in interest rates related

to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the bankers' acceptance rate, plus 0.15%.

*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 Remote Communities 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 Company's total provision for bad debts was $296 thousand (2012 – $302 thousand). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2013, approximately 47% of the Company's current accounts receivable were aged more than 60 days (2012 – 34%). Sufficient allowances have been recorded to reflect the risk of potential credit losses.

*Liquidity Risk*

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities 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 $5,657 thousand (2012 – $6,863 thousand) are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2013, Hydro One Remote Communities had long-term debt in the principal l amount of $23,000 thousand (2012 – $23,000 thousand). No long-term debt matures during the next year. Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $1,237 thousand (2012 – $1,237 thousand). Principal repayments and interest payments are summarized by the number of years to maturity in the following table.

| Years to Maturity | Principal Outstanding on Long-term Debt *(thousands of dollars)* | Interest Payments *(thousands of dollars)* |
|---|---|---|
| 1 year | – | 1,237 |
| 2 years | – | 1,237 |
| 3 years | – | 1,237 |
| 4 years | – | 1,237 |
| 5 years | – | 1,237 |
| | – | 6,185 |
| 6 – 10 years | – | 6,185 |
| Over 10 years | 23,000 | 15,468 |
| | 23,000 | 27,838 |

## 12. 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. 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 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.

Company and employees' 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, Hydro One Remote Communities charged $775 thousand (2012 – $537 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $250 thousand (2012 – $223 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2013 were $264 thousand (2012 – $259 thousand). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $205 thousand (2012 – increased by $1,941 thousand) and recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Accrued liabilities | 300 | 300 |
| Post-retirement and post-employment benefit liability | 12,088 | 11,532 |
| | 12,388 | 11,832 |

## 13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2013 and 2012:

| *December 31 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Environmental liabilities, January 1 | 11,880 | 14,579 |
| Interest accretion | 330 | 399 |
| Expenditures | (1,656) | (2,515) |
| Revaluation adjustment | 2,872 | (583) |
| Environmental liabilities, December 31 | 13,426 | 11,880 |
| Less: current portion | 2,427 | 1,823 |
| | 10,999 | 10,057 |

The following table illustrates 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 (thousands of dollars)* | **2013** | **2012** |
|---|---|---|
| Undiscounted environmental liabilities, December 31 | 14,014 | 12,503 |
| Less: discounting accumulated liabilities to present value | 588 | 623 |
| Discounted environmental liabilities, December 31 | 13,426 | 11,880 |

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2013 and in total thereafter are as follows: 2014 – $2,427 thousand; 2015 – $2,175 thousand; 2016 – $2,844 thousand; 2017 – $1,261 thousand; 2018 – $1,651 thousand; and thereafter – $3,653 thousand. These expenditures are expected to be incurred over the period from 2014 to 2020.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting its expectation that future environmental costs will be recoverable in rates.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.57% to 4.87%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

As a result of its annual review of the environmental liabilities, the Company recorded a revaluation adjustment to increase the LAR environmental liability by $2,872 thousand (2012 – decrease by $583 thousand).

## 14. SHARE CAPITAL

### Common Shares

The Company has 2 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

### Dividends

The Company has no retained earnings and does not pay dividends under its breakeven business model.

## 15. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities 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 Hydro One Remote Communities because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One Remote Communities are described below.

Hydro One Remote Communities receives amounts for RRRP from the IESO. RRRP amounts received for the year ended December 31, 2013 were $33,046 thousand (2012 – $27,549 thousand). Consistent with its breakeven business model, the Company recognized $34,245 thousand as RRRP revenue in 2013 (2012 – $31,506 thousand). This 2013 revenue exceeded

amounts received by $1,199 thousand (2012 – $3,957 thousand) and the RRPR variance account balance was adjusted by this amount.

The recovery of PILs was received or receivable from the OEFC.

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

| *December 31 (thousands of dollars)* | 2013 | 2012 |
|---|---|---|
| Accounts receivable | 97 | 88 |
| Income tax receivable | 2,697 | 1,589 |

Transactions with 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.

**Hydro One and Subsidiaries**

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its other 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 corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2013 revenues include $195 thousand (2012 – $130 thousand) related to the provision of services to Hydro One and its other subsidiaries. 2013 operation, maintenance and administration costs include $3,475 thousand (2012 – $2,607 thousand) related to the purchase of services from Hydro One and its other subsidiaries.

The Company's long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One and its other subsidiaries. Financing charges include interest expense on the long-term debt in the amount of $1,237 thousand (2012 – $1,237 thousand), and interest expense on the inter-company demand facility in the amount of $216 thousand (2012 – $83 thousand). At December 31, 2013, the Company had accrued interest payable to Hydro One totaling $142 thousand (2012 – $142 thousand).

## 16. STATEMENTS OF CASH FLOWS

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

| *Year ended December 31 (thousands of dollars)* | 2013 | 2012 |
|---|---|---|
| Accounts receivable | (802) | (258) |
| Materials and supplies | 443 | 638 |
| Income taxes receivable | (1,108) | (1,426) |
| Long-term accounts receivable | (256) | (49) |
| Accounts payable | (284) | (443) |
| Accrued liabilities | (1,526) | 91 |
| Post-retirement and post-employment benefit liability | 760 | 500 |
| | (2,773) | (947) |
| **Supplementary information:** | | |
| Net interest paid | 1,453 | 1,320 |

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any PILs paid are fully recovered.

## 17. CONTINGENCIES

### Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

### Transfer of Assets

The transfer orders by which the Company acquired Ontario Hydro's remote communities business on April 1, 1999 did not transfer title to some assets located on lands held for First Nation bands under the *Indian Act* (Canada). Currently, OEFC holds legal title to these assets and the Company manages them until the Company has obtained necessary authorizations to complete the title transfer. To occupy reserve land, 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 band, OEFC and any First Nation individuals who have occupancy rights. The agreement includes provisions whereby the First Nation band consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. 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 the First Nation bands. In 2013, the Company paid approximately $2 million (2012 – $1 million) in respect of these consents. OEFC will continue to hold these assets until the Company is able to negotiate agreements with the First Nation bands and occupants. If the Company cannot reach satisfactory agreements and obtain federal permits, the Company may have to relocate these assets from the reserve lands to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on the Company's net income if the Company is not able to recover them in future rate orders.

## 18. COMMITMENTS

### Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years.

At December 31, 2013, the future minimum lease payments under this operating lease are as follows:

| *Year ended December 31 (thousands of dollars)* | **2013** |
|---|---|
| Within one year | 120 |
| After one year but not more than five years | 510 |
| More than five years | 600 |
| | 1,230 |

During the year ended December 31, 2013, the Company made upfront lease payments totalling $1 million which is being amortized based over the contractual term of the lease.

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**SCHEDULE 100**

Form identifier 100

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

### Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 11,963,000 | 9,892,000 |
| | Total tangible capital assets | 2008 | + | 64,028,000 | 63,613,000 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 23,256,000 | 25,779,000 |
| | Total intangible capital assets | 2178 | + | | |
| | Total accumulated amortization of intangible capital assets | 2179 | – | | |
| | Total long-term assets | 2589 | + | 20,960,000 | 19,339,000 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 73,695,000 | 67,065,000 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 23,939,000 | 18,325,000 |
| | Total long-term liabilities | 3450 | + | 50,325,000 | 49,322,000 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 74,264,000 | 67,647,000 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | -569,000 | -582,000 |
| | **Total liabilities and shareholder equity** | 3640 | = | 73,695,000 | 67,065,000 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | | |

* Generic item

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**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | Ontario Hydro Remote Communities Service Company Inc. |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Income statement information** | | | | |
| | Total sales of goods and services | 8089 | + | 50,035,000 | 46,766,000 |
| | Cost of sales | 8518 | – | 25,568,000 | 24,306,000 |
| | **Gross profit/loss** | 8519 | = | 24,467,000 | 22,460,000 |
| | Cost of sales | 8518 | + | 25,568,000 | 24,306,000 |
| | Total operating expenses | 9367 | + | 25,558,000 | 23,896,000 |
| | **Total expenses** (mandatory field) | 9368 | = | 51,126,000 | 48,202,000 |
| | Total revenue (mandatory field) | 8299 | + | 50,035,000 | 46,766,000 |
| | Total expenses (mandatory field) | 9368 | – | 51,126,000 | 48,202,000 |
| | **Net non-farming income** | 9369 | = | -1,091,000 | -1,436,000 |
| | **Farming income statement information** | | | | |
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | -1,091,000 | -1,436,000 |
| | **Total other comprehensive income** | 9998 | = | 13,000 | 12,000 |
| | **Extraordinary items and income (linked to Schedule 140)** | | | | |
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | -1,091,000 | -1,436,000 |
| | Future (deferred) income tax provision | 9995 | – | | |
| | Total – Other comprehensive income | 9998 | + | 13,000 | 12,000 |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 13,000 | 12,000 |

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**Schedule 141**

# Notes checklist

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

**Note**

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: . . . **198**

Completed an auditor's report . . . 1 [X]

Completed a review engagement report . . . 2 [ ]

Conducted a compilation engagement . . . 3 [ ]

## Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . **099** 1 Yes [ ] 2 No [X]

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: . . . **110**

Prepared the tax return (financial statements prepared by client) . . . 1 [X]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . 2 [ ]

Were notes to the financial statements prepared? . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . **108** 1 Yes [ ] 2 No [X]

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income Increase (decrease) | | In OCI Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes [X] 2 No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

**SCHEDULE 100**

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

### Assets – lines 1000 to 2599

| | | | | | |
|---|---|---|---|---|---|
| 1062 | 4,995,000 | 1066 | 2,697,000 | 1122 | 1,736,000 |
| 1480 | 2,427,000 | 1481 | 108,000 | 1599 | 11,963,000 |
| 1740 | 50,010,000 | 1741 | -21,265,000 | 1900 | 10,545,000 |
| 1901 | -1,991,000 | 1920 | 3,473,000 | 2008 | 64,028,000 |
| 2009 | -23,256,000 | 2420 | 16,721,000 | 2421 | 4,239,000 |
| 2589 | 20,960,000 | 2599 | 73,695,000 | | |

### Liabilities – lines 2600 to 3499

| | | | | | |
|---|---|---|---|---|---|
| 2620 | 5,657,000 | 2629 | 142,000 | 2860 | 18,031,000 |
| 2960 | 109,000 | 3139 | 23,939,000 | 3140 | 23,000,000 |
| 3320 | 15,237,000 | 3321 | 12,088,000 | 3450 | 50,325,000 |
| 3499 | 74,264,000 | | | | |

### Shareholder equity – lines 3500 to 3640

| | | | | | |
|---|---|---|---|---|---|
| 3580 | -569,000 | 3620 | -569,000 | 3640 | 73,695,000 |

### Retained earnings – lines 3660 to 3849

| | |
|---|---|
| 3849 | 0 |

**SCHEDULE 125**

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

### Description

Operating name . . . . . . . . **0001** Ontario Hydro Remote Communities Service Company Inc.

Sequence number . . . . . . . **0003** 01

### Other comprehensive income – lines 7000 to 7020

| | |
|---|---|
| **7020** | 13,000 |

### Revenue – lines 8000 to 8299

| | | | | | |
|---|---|---|---|---|---|
| **8000** | 50,035,000 | **8089** | 50,035,000 | **8299** | 50,035,000 |

### Cost of sales – lines 8300 to 8519

| | | | | | |
|---|---|---|---|---|---|
| **8408** | 25,568,000 | **8518** | 25,568,000 | **8519** | 24,467,000 |

### Operating expenses – lines 8520 to 9369

| | | | | | |
|---|---|---|---|---|---|
| **8670** | 4,809,000 | **8714** | 1,104,000 | **9270** | 19,645,000 |
| **9367** | 25,558,000 | **9368** | 51,126,000 | **9369** | -1,091,000 |

### Extraordinary items and taxes – lines 9970 to 9999

| | | | | | |
|---|---|---|---|---|---|
| **9970** | -1,091,000 | **9990** | -1,091,000 | **9998** | 13,000 |
| **9999** | 13,000 | | | | |

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# Net Income (Loss) for Income Tax Purposes

**SCHEDULE 1**

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

| | | | | | |
|---|---|---|---|---|---|
| Amount calculated on line 9999 from Schedule 125 | | | | 13,000 | A |
| **Add:** | | | | | |
| Provision for income taxes – current | | 101 | -1,091,000 | | |
| Amortization of tangible assets | | 104 | 4,809,000 | | |
| Non-deductible meals and entertainment expenses | | 121 | 32,011 | | |
| Reserves from financial statements – balance at the end of the year | | 126 | 23,828,275 | | |
| Subtotal of additions | | | 27,578,286 ▶ | 27,578,286 | |
| **Other additions:** | | | | | |
| Debt issue expense | | 208 | 15,869 | | |
| **Miscellaneous other additions:** | | | | | |
| 600 OPEB US GAAP Valuation | | 290 | 205,194 | | |
| 601 Unpaid Bonus Accrual | | 291 | 8,461 | | |
| 602 2013 Ontario Co-op & Apprentice credits | | 292 | 30,604 | | |
| 604 Computer software expensed | 1,011 | | | | |
| Total | 1,011 | 294 | 1,011 | | |
| Subtotal of other additions | | 199 | 261,139 ▶ | 261,139 | |
| **Total additions** | | 500 | 27,839,425 ▶ | 27,839,425 | B |
| Amount A **plus** amount B | | | | 27,852,425 | |
| **Deduct:** | | | | | |
| Capital cost allowance from Schedule 8 | | 403 | 2,826,199 | | |
| Reserves from financial statements – balance at the beginning of the year | | 414 | 22,852,881 | | |
| Subtotal of deductions | | | 25,679,080 ▶ | 25,679,080 | |
| **Other deductions:** | | | | | |
| Non-taxable/deductible other comprehensive income items | | 347 | 13,000 | | |
| **Miscellaneous other deductions:** | | | | | |
| 700 Reverse Environmental interest & valuation adjusts in S13 | | 390 | 3,202,325 | | |
| 703 Removal expense added back via depreciation | 213,176 | | | | |
| Total | 213,176 | 393 | 213,176 | | |
| 704 Refer to supporting schedule | 1,022,539 | | | | |
| OPEB costs capitalized | 246,812 | | | | |
| Total | 1,269,351 | 394 | 1,269,351 | | |
| Subtotal of other deductions | | 499 | 4,697,852 ▶ | 4,697,852 | |
| **Total deductions** | | 510 | 30,376,932 ▶ | 30,376,932 | |
| **Net income (loss) for income tax purposes** – enter on line 300 of the T2 return | | | | -2,524,507 | |

# Attached Schedule with Total

Line 208 – Debt issue expense

Title Line 208 – Debt issue expense

| Description | Amount | |
|---|---|---|
| Amortization underwriting fee (761780) | 2,251 | 00 |
| Amortization of Hedge loss (761770) | 13,010 | 00 |
| Bond Discount (761120,761130) | 608 | 00 |
| **Total** | 15,869 | 00 |

# Attached Schedule with Total

Line 704 – Amount

Title Line 704 – Amount

| Description | Amount |
|---|---|
| Capitalized interest | 376,006.00 |
| Capitalized overhead | 308,916.00 |
| Pension costs capitalized | 337,617.00 |
| | |
| **Total** | 1,022,539.00 |

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**Schedule 4**

# Corporation Loss Continuity and Application

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the federal *Income Tax Act.*

## Part 1 – Non-capital losses

**Determination of current-year non-capital loss**

| | | | | |
|---|---|---|---|---|
| Net income (loss) for income tax purposes | | | -2,524,507 | A |
| **Deduct:** (increase a loss) | | | | |
| Net capital losses deducted in the year (enter as a positive amount) | | a | | |
| Taxable dividends deductible under section 112 or subsection 113(1) or 138(6) | | b | | |
| Amount of Part VI.1 tax deductible | | c | | |
| Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2) | | d | | |
| Subtotal (total of amounts a to d) | | ▶ | | B |
| Subtotal (amount A **minus** amount B; if positive, enter "0") | | | -2,524,507 | C |
| **Deduct:** (increase a loss) | | | | |
| Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions | | | | D |
| Subtotal (amount C **minus** amount D) | | | -2,524,507 | E |
| **Add:** (decrease a loss) | | | | |
| Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss) | | | | F |
| Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0") | | | -2,524,507 | G |

If amount G is negative, enter it on line 110 as a positive.

**Continuity of non-capital losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Non-capital loss at the end of the previous tax year | | | e | | |
| **Deduct:** Non-capital loss expired* | 100 | | f | | |
| Non-capital losses at the beginning of the tax year (amount e **minus** amount f) | 102 | | ▶ | | H |
| **Add:** | | | | | |
| Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation | 105 | | g | | |
| Current-year non-capital loss (from amount G) | 110 | 2,524,507 | h | | |
| Subtotal (amount g **plus** amount h) | | 2,524,507 | ▶ | 2,524,507 | I |
| Subtotal (amount H **plus** amount I) | | | | 2,524,507 | J |

* A non-capital loss expires as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004;
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004; and
- after **10** tax years if it arose in a tax year ending after March 22, 2004.

## Part 1 – Non-capital losses (continued)

**Deduct:**

| | | | | | |
|---|---|---|---|---|---|
| Other adjustments (includes adjustments for an acquisition of control) | 150 | | i | | |
| Section 80 – Adjustments for forgiven amounts | 140 | | j | | |
| Subsection 111(10) – Adjustments for fuel tax rebate | | | j.1 | | |
| Non-capital losses of previous tax years applied in the current tax year<br>Enter amount k on line 331 of the T2 return. | 130 | | k | | |
| Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax** | 135 | | l | | |
| Subtotal (total of amounts i to l) | | | ▶ | | K |
| Non-capital losses before any request for a carryback (amount J **minus** amount K) | | | | 2,524,507 | L |

**Deduct – Request to carry back non-capital loss to:**

| | | | | | |
|---|---|---|---|---|---|
| First previous tax year to reduce taxable income | 901 | | m | | |
| Second previous tax year to reduce taxable income | 902 | | n | | |
| Third previous tax year to reduce taxable income | 903 | 2,435,715 | o | | |
| First previous tax year to reduce taxable dividends subject to Part IV tax | 911 | | p | | |
| Second previous tax year to reduce taxable dividends subject to Part IV tax | 912 | | q | | |
| Third previous tax year to reduce taxable dividends subject to Part IV tax | 913 | | r | | |
| Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r) | | 2,435,715 | ▶ | 2,435,715 | M |
| Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M) | 180 | | | 88,792 | N |

** Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation.*

## Part 2 – Capital losses

**Continuity of capital losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Capital losses at the end of the previous tax year | 200 | | a | | |
| Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation | 205 | | b | | |
| Subtotal (amount a **plus** amount b) | | | ▶ | | A |
| **Deduct:** | | | | | |
| Other adjustments (includes adjustments for an acquisition of control) | 250 | | c | | |
| Section 80 – Adjustments for forgiven amounts | 240 | | d | | |
| Subtotal (amount c **plus** amount d) | | | ▶ | | B |
| Subtotal (amount A **minus** amount B) | | | | | C |
| **Add:** Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*) | 210 | | | | D |
| Unused non-capital losses that expired in the tax year* | | | e | | |
| Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year** | | | f | | |
| Enter amount e or f, whichever is less | 215 | | | | |
| ABILs expired as non-capital loss: line 215 **divided** by 0.500000 | 220 | | | | E |
| Subtotal (total of amounts C to E) | | | | | F |

**Note**
If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

## Part 2 – Capital losses (continued)

**Deduct:** Capital losses from previous tax years applied against the current-year net capital gain*** . . . 225 ______ G

Capital losses before any request for a carryback (amount F **minus** amount G) ______ H

**Deduct – Request to carry back capital loss to****:**

| | Capital gain (100%) | | Amount carried back (100%) | |
|---|---|---|---|---|
| First previous tax year | | 951 | | g |
| Second previous tax year | | 952 | | h |
| Third previous tax year | | 953 | | i |

Subtotal (total of amounts g to i) ______ ▶ ______ I

Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I) 280 ______ J

*** To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

**** On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

## Part 3 – Farm losses

**Continuity of farm losses and request for a carryback**

Farm losses at the end of the previous tax year . . . ______ a

**Deduct:** Farm loss expired* . . . 300 ______ b

Farm losses at the beginning of the tax year (amount a **minus** amount b) . . . 302 ______ ▶ ______ A

**Add:**

Farm losses transferred on the amalgamation or the windup of a subsidiary corporation . . . 305 ______ c

Current-year farm loss (amount F in Part 1) . . . 310 ______ d

Subtotal (amount c **plus** amount d) ______ ▶ ______ B

Subtotal (amount A **plus** amount B) ______ C

**Deduct:**

Other adjustments (includes adjustments for an acquisition of control) . . . 350 ______ e

Section 80 – Adjustments for forgiven amounts . . . 340 ______ f

Farm losses of previous tax years applied in the current tax year . . . 330 ______ g
Enter amount g on line 334 of the T2 return.

Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax** . . . 335 ______ h

Subtotal (total of amounts e to h) ______ ▶ ______ D

Farm losses before any request for a carryback (amount C **minus** amount D) ______ E

**Deduct – Request to carry back farm loss to:**

First previous tax year to reduce taxable income . . . 921 ______ i

Second previous tax year to reduce taxable income . . . 922 ______ j

Third previous tax year to reduce taxable income . . . 923 ______ k

First previous tax year to reduce taxable dividends subject to Part IV tax . . . 931 ______ l

Second previous tax year to reduce taxable dividends subject to Part IV tax . . . 932 ______ m

Third previous tax year to reduce taxable dividends subject to Part IV tax . . . 933 ______ n

Subtotal (total of amounts i to n) ______ ▶ ______ F

Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F) 380 ______ G

* A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

** Amount h is the total of lines 340 and 345 from Schedule 3.

## Part 4 – Restricted farm losses

**Current-year restricted farm loss**

Total losses for the year from farming business . . . . . . **485** ______ A

**Minus** the deductible farm loss:

(amount A above ______ – $2,500) **divided** by 2 = ______ a

Amount a or $ 15,000 *, whichever is less . . . . . . ______ ▶ ______ b

**2,500** c

Subtotal (amount b **plus** amount c) 2,500 ▶ 2,500 B

Current-year restricted farm loss (amount A **minus** amount B) ______ C

**Continuity of restricted farm losses and request for a carryback**

Restricted farm losses at the end of the previous tax year . . . . . . ______ d

**Deduct:** Restricted farm loss expired** . . . . . . **400** ______ e

Restricted farm losses at the beginning of the tax year (amount d **minus** amount e) . . . . . . **402** ______ ▶ ______ D

**Add:**

Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation . . . . . . **405** ______ f

Current-year restricted farm loss (from amount C) . . . . . . **410** ______ g

Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes.*

Subtotal (amount f **plus** amount g) ______ ▶ ______ E

Subtotal (amount D **plus** amount E) ______ F

**Deduct:**

Restricted farm losses from previous tax years applied against current farming income . . . . . **430** ______ h

Enter amount h on line 333 of the T2 return.

Section 80 – Adjustments for forgiven amounts . . . . . . **440** ______ i

Other adjustments . . . . . . **450** ______ j

Subtotal (total of amounts h to j) ______ ▶ ______ G

Restricted farm losses before any request for a carryback (amount F **minus** amount G) ______ H

**Deduct – Request to carry back restricted farm loss to:**

First previous tax year to reduce farming income . . . . . . **941** ______ k

Second previous tax year to reduce farming income . . . . . . **942** ______ l

Third previous tax year to reduce farming income . . . . . . **943** ______ m

Subtotal (total of amounts k to m) ______ ▶ ______ I

Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I) **480** ______ J

**Note**

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

** A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

## Part 5 – Listed personal property losses

**Continuity of listed personal property loss and request for a carryback**

| | | | | |
|---|---|---|---|---|
| Listed personal property losses at the end of the previous tax year | | a | | |
| **Deduct:** Listed personal property loss expired after seven tax years | 500 | b | | |
| Listed personal property losses at the beginning of the tax year (amount a **minus** amount b) | 502 | ► | | A |
| **Add:** Current-year listed personal property loss (from Schedule 6) | | | 510 | B |
| Subtotal (amount A **plus** amount B) | | | | C |

**Deduct:**

| | | | | |
|---|---|---|---|---|
| Previous year personal property losses applied in the current tax year against listed personal property gains | 530 | c | | |
| Enter amount c on line 655 of Schedule 6. | | | | |
| Other adjustments | 550 | d | | |
| Subtotal (amount c **plus** amount d) | | ► | | D |
| Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D) | | | | E |

**Deduct – Request to carry back listed personal property loss to:**

| | | | | |
|---|---|---|---|---|
| First previous tax year to reduce listed personal property gains | 961 | e | | |
| Second previous tax year to reduce listed personal property gains | 962 | f | | |
| Third previous tax year to reduce listed personal property gains | 963 | g | | |
| Subtotal (total of amounts e to g) | | ► | | F |
| Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F) | | | 580 | G |

## Part 7 – Limited partnership losses

### Current-year limited partnership losses

| 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|
| Partnership identifier 600 | Tax year ending YYYY/MM/DD 602 | Corporation's share of limited partnership loss 604 | Corporation's at-risk amount 606 | Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608 | Column 4 **minus** column 5 (if negative, enter "0") | Current-year limited partnership losses (column 3 **minus** 6) 620 |
| | | | | | | |

**Total** (enter this amount on line 222 of Schedule 1)

### Limited partnership losses from previous tax years that may be applied in the current year

| 8 | 9 | 10 | 11 | 12 | 13 | 14 |
|---|---|---|---|---|---|---|
| Partnership identifier 630 | Tax year ending YYYY/MM/DD 632 | Limited partnership losses at the end of the previous tax year 634 | Corporation's at-risk amount 636 | Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638 | Column 11 **minus** column 12 (if negative, enter "0") | Limited partnership losses that may be applied in the year (the lesser of columns 10 and 13) 650 |
| | | | | | | |

### Continuity of limited partnership losses that can be carried forward to future tax years

| 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|
| Partnership identifier 660 | Limited partnership losses at the end of the previous tax year 662 | Limited partnership losses transferred on an amalgamation or the windup of a subsidiary 664 | Current-year limited partnership losses (from column 7) 670 | Limited partnership losses applied in the current year (cannot be more than column 14) 675 | Current year limited partnership losses closing balance to be carried forward to future years (column 16 **plus** column 17 **plus** column 18 **minus** column 19) 680 |
| | | | | | |

**Total** (enter this amount on line 335 of the T2 return)

**Note**

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

## Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 190 Yes ☐

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

**Note**

This election applies only for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for tax years that begin after the start of the wind-up.

# Non-Capital Loss Continuity Workchart

## Part 6 – Analysis of balance of losses by year of origin

### Non-capital losses – losses that can be carried forward over 20 years

| Year of origin | Balance at beginning of year | Loss incurred in current year | Adjustments and transfers | Loss carried back Parts I & IV | Applied to reduce Taxable income | Applied to reduce Part IV tax | Balance at end of year |
|---|---|---|---|---|---|---|---|
| Current | N/A | 2,524,507 | | 2,435,715 | N/A | | 88,792 |
| 1st preceding taxation year 2012-12-31 | | N/A | | N/A | | | |
| 2nd preceding taxation year 2011-12-31 | | N/A | | N/A | | | |
| 3rd preceding taxation year 2010-12-31 | | N/A | | N/A | | | |
| 4th preceding taxation year 2009-12-31 | | N/A | | N/A | | | |
| 5th preceding taxation year 2008-12-31 | | N/A | | N/A | | | |
| 6th preceding taxation year 2007-12-31 | | N/A | | N/A | | | |
| 7th preceding taxation year 2006-12-31 | | N/A | | N/A | | | |
| 8th preceding taxation year 2005-12-31 | | N/A | | N/A | | | |
| 9th preceding taxation year 2004-12-31 | | N/A | | N/A | | | |
| 10th preceding taxation year 2003-12-31 | | N/A | | N/A | | | |
| 11th preceding taxation year 2002-12-31 | | N/A | | N/A | | | |
| 12th preceding taxation year 2001-12-31 | | N/A | | N/A | | | |
| 13th preceding taxation year 2000-12-31 | | N/A | | N/A | | | |
| 14th preceding taxation year 1999-12-31 | | N/A | | N/A | | | |
| 15th preceding taxation year 1999-03-31 | | N/A | | N/A | | | |
| 16th preceding taxation year 1998-03-31 | | N/A | | N/A | | | |
| 17th preceding taxation year 1997-03-31 | | N/A | | N/A | | | |
| 18th preceding taxation year 1996-03-31 | | N/A | | N/A | | | |
| 19th preceding taxation year 1995-03-31 | | N/A | | N/A | | | |
| 20th preceding taxation year 1994-03-31 | | N/A | | N/A | | | * |
| Total | | 2,524,507 | | 2,435,715 | | | 88,792 |

* This balance expires this year and will not be available next year.

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**Schedule 5**

# TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

| Corporation's name | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

## Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

| A<br>Jurisdiction<br>Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. * | B<br>Total salaries and wages paid in jurisdiction | C<br>(B x taxable income**) / G | D<br>Gross revenue | E<br>(D x taxable income**) / H | F<br>Allocation of taxable income (C + E) x 1/2***<br>(where either G or H is nil, do not multiply by 1/2) |
|---|---|---|---|---|---|
| Newfoundland and Labrador 003 1 Yes ☐ | 103 | | 143 | | |
| Newfoundland and Labrador offshore 004 1 Yes ☐ | 104 | | 144 | | |
| Prince Edward Island 005 1 Yes ☐ | 105 | | 145 | | |
| Nova Scotia 007 1 Yes ☐ | 107 | | 147 | | |
| Nova Scotia offshore 008 1 Yes ☐ | 108 | | 148 | | |
| New Brunswick 009 1 Yes ☐ | 109 | | 149 | | |
| Quebec 011 1 Yes ☐ | 111 | | 151 | | |
| Ontario 013 1 Yes ☐ | 113 | | 153 | | |
| Manitoba 015 1 Yes ☐ | 115 | | 155 | | |
| Saskatchewan 017 1 Yes ☐ | 117 | | 157 | | |
| Alberta 019 1 Yes ☐ | 119 | | 159 | | |
| British Columbia 021 1 Yes ☐ | 121 | | 161 | | |
| Yukon 023 1 Yes ☐ | 123 | | 163 | | |
| Northwest Territories 025 1 Yes ☐ | 125 | | 165 | | |
| Nunavut 026 1 Yes ☐ | 126 | | 166 | | |
| Outside Canada 027 1 Yes ☐ | 127 | | 167 | | |
| **Total** | 129 G | | 169 H | | |

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

**Notes:**

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

## Part 2 – Ontario tax payable, tax credits, and rebates

| Total taxable income | Income eligible for small business deduction | Provincial or territorial allocation of taxable income | Provincial or territorial tax payable before credits |
|---|---|---|---|
| | | | |

| | Line | Amount | | Total | |
|---|---|---|---|---|---|
| **Ontario basic income tax** (from Schedule 500) | 270 | | | | |
| **Deduct:** Ontario small business deduction (from Schedule 500) | 402 | | | | |
| Subtotal | | | ► | | A6 |
| **Add:** | | | | | |
| Ontario additional tax re Crown royalties (from Schedule 504) | 274 | | | | |
| Ontario transitional tax debits (from Schedule 506) | 276 | | | | |
| Recapture of Ontario research and development tax credit (from Schedule 508) | 277 | | | | |
| Subtotal | | | ► | | B6 |
| Subtotal (amount A6 **plus** amount B6) | | | | | C6 |
| **Deduct:** | | | | | |
| Ontario resource tax credit (from Schedule 504) | 404 | | | | |
| Ontario tax credit for manufacturing and processing (from Schedule 502) | 406 | | | | |
| Ontario foreign tax credit (from Schedule 21) | 408 | | | | |
| Ontario credit union tax reduction (from Schedule 500) | 410 | | | | |
| Ontario transitional tax credits (from Schedule 506) | 414 | | | | |
| Ontario political contributions tax credit (from Schedule 525) | 415 | | | | |
| Ontario tax credit for the purchase of vehicles that use natural gas as a fuel | | | | | |
| Subtotal | | | ► | | D6 |
| Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") | | | | | E6 |
| **Deduct:** Ontario research and development tax credit (from Schedule 508) | | | | 416 | |
| Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0") | | | | | F6 |
| **Deduct:** Ontario corporate minimum tax credit (from Schedule 510) | | | | 418 | |
| Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0") | | | | | G6 |
| **Add:** | | | | | |
| Ontario corporate minimum tax (from Schedule 510) | 278 | | | | |
| Ontario special additional tax on life insurance corporations (from Schedule 512) | 280 | | | | |
| Subtotal | | | ► | | H6 |
| Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) | | | | | I6 |
| **Deduct:** | | | | | |
| Ontario qualifying environmental trust tax credit | 450 | | | | |
| Ontario co-operative education tax credit (from Schedule 550) | 452 | 12,000 | | | |
| Ontario apprenticeship training tax credit (from Schedule 552) | 454 | 18,604 | | | |
| Ontario computer animation and special effects tax credit (from Schedule 554) | 456 | | | | |
| Ontario film and television tax credit (from Schedule 556) | 458 | | | | |
| Ontario production services tax credit (from Schedule 558) | 460 | | | | |
| Ontario interactive digital media tax credit (from Schedule 560) | 462 | | | | |
| Ontario sound recording tax credit (from Schedule 562) | 464 | | | | |
| Ontario book publishing tax credit (from Schedule 564) | 466 | | | | |
| Ontario innovation tax credit (from Schedule 566) | 468 | | | | |
| Ontario business-research institute tax credit (from Schedule 568) | 470 | | | | |
| Other Ontario tax credits | | | | | |
| Subtotal | | 30,604 | ► | 30,604 | J6 |
| **Net Ontario tax payable or refundable credit** (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255. | | | | 290 -30,604 | K6 |

## Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

**Net provincial and territorial tax payable or refundable credits** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **255** -30,604

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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**SCHEDULE 8**

# CAPITAL COST ALLOWANCE (CCA)

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? 101 1 Yes [ ] 2 No [X]

| | 1 Class number (See Note) 200 | Description | 2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201 | 3 Cost of acquisitions during the year (new property must be available for use)* 203 | 4 Net adjustments** 205 | 5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207 | 6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211 | 7 Reduced undepreciated capital cost | 8 CCA rate % **** 212 | 9 Recapture of capital cost allowance (line 107 of Schedule 1) 213 | 10 Terminal loss (line 404 of Schedule 1) 215 | 11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217 | 12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | 17,529,689 | 525,536 | | 0 | 262,768 | 17,792,457 | 4 | 0 | 0 | 711,698 | 17,343,527 |
| 2. | 2 | | 523,488 | | | 0 | | 523,488 | 6 | 0 | 0 | 31,409 | 492,079 |
| 3. | 3 | | 743,061 | | | 0 | | 743,061 | 5 | 0 | 0 | 37,153 | 705,908 |
| 4. | 6 | | 2,798,765 | 2,068,214 | | 0 | 1,034,107 | 3,832,872 | 10 | 0 | 0 | 383,287 | 4,483,692 |
| 5. | 8 | | 867,600 | 215,156 | | 0 | 107,578 | 975,178 | 20 | 0 | 0 | 195,036 | 887,720 |
| 6. | 10 | | 373,003 | 35,011 | | 0 | 17,506 | 390,508 | 30 | 0 | 0 | 117,152 | 290,862 |
| 7. | 12 | | 2,572 | 351 | | 0 | 176 | 2,747 | 100 | 0 | 0 | 2,747 | 176 |
| 8. | 13 | Hillsport Water Well | 38,999 | | | 0 | | 38,999 | NA | 0 | 0 | 1,019 | 37,980 |
| 9. | 13 | Oba Water Well | 22,260 | | | 0 | | 22,260 | NA | 0 | 0 | 2,782 | 19,478 |
| 10. | 17 | | 9,888,184 | 4,254,564 | | 0 | 2,127,282 | 12,015,466 | 8 | 0 | 0 | 961,237 | 13,181,511 |
| 11. | 42 | | 191,858 | | | 0 | | 191,858 | 12 | 0 | 0 | 23,023 | 168,835 |
| 12. | 43.1 | | 614 | 981,967 | | 0 | 490,984 | 491,597 | 30 | 0 | 0 | 147,479 | 835,102 |
| 13. | 45 | | 1,225 | | | 0 | | 1,225 | 45 | 0 | 0 | 551 | 674 |
| 14. | 47 | | 2,512,031 | 224,212 | | 14 | 112,099 | 2,624,130 | 8 | 0 | 0 | 209,930 | 2,526,299 |
| 15. | 50 | | 3,083 | | | 0 | | 3,083 | 55 | 0 | 0 | 1,696 | 1,387 |
| | | **Totals** | 35,496,432 | 8,305,011 | | 14 | 4,152,500 | 39,648,929 | | | | 2,826,199 | 40,975,230 |

**Note:** Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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**SCHEDULE 9**

# RELATED AND ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

| | Name 100 | Country of residence (other than Canada) 200 | Business number (see note 1) 300 | Relationship code (see note 2) 400 | Number of common shares you own 500 | % of common shares you own 550 | Number of preferred shares you own 600 | % of preferred shares you own 650 | Book value of capital stock 700 |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Hydro One Inc. | | 86999 4731 RC0001 | 1 | | | | | |
| 2. | Hydro One Networks Inc. | | 87086 5821 RC0001 | 3 | | | | | |
| 3. | Hydro One Telecom Inc. | | 86800 1066 RC0001 | 3 | | | | | |
| 4. | Hydro One Telecom Link Limited | | 88786 7513 RC0001 | 3 | | | | | |
| 5. | Hydro One Brampton Networks Inc. | | 86486 7635 RC0001 | 3 | | | | | |
| 6. | Hydro One Lake Erie Link Managem | | 87892 1519 RC0001 | 3 | | | | | |
| 7. | Hydro One Lake Erie Link Company | | 87560 6519 RC0001 | 3 | | | | | |
| 8. | Hydro One B2M LP Inc. | | 81838 2046 RC0001 | 3 | | | | | |
| 9. | B2M GP Inc. | | 81838 1840 RC0001 | 3 | | | | | |
| 10. | Hydro One B2M Holdings Inc. | | 82217 7531 RC0001 | 3 | | | | | |
| 11. | 1908872 Ontario Inc. | | 82581 6838 RC0001 | 3 | | | | | |
| 12. | 1908873 Ontario Inc. | | 83392 0978 RC0001 | 3 | | | | | |
| 13. | 1893080 Ontario Inc. | | 82217 7333 RC0001 | 3 | | | | | |

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

# Continuity of financial statement reserves (not deductible)

## Financial statement reserves (not deductible)

| | Description | Balance at the beginning of the year | Transfer on an amalgamation or the wind-up of a subsidiary | Add | Deduct | Balance at the end of the year |
|---|---|---|---|---|---|---|
| 1 | OPEB Liability | 11,832,479 | | 555,363 | | 12,387,842 |
| 2 | RRPP Rev Var (427191) | -786,719 | | | 1,198,744 | -1,985,463 |
| 3 | Environmental Liability | 11,879,741 | | 1,546,155 | | 13,425,896 |
| 4 | Reg Asset - IFRS Costs | -72,620 | | | -72,620 | |
| 5 | | | | | | |
| | Reserves from Part 2 of Schedule 13 | | | | | |
| | **Totals** | 22,852,881 | | 2,101,518 | 1,126,124 | 23,828,275 |

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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**SCHEDULE 14**

## MISCELLANEOUS PAYMENTS TO RESIDENTS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

| | Name of recipient 100 | Address of recipient 200 | Royalties 300 | Research and development fees 400 | Management fees 500 | Technical assistance fees 600 | Similar payments 700 |
|---|---|---|---|---|---|---|---|
| 1 | Hydro One Networks Inc | 483 Bay Street<br><br>Toronto<br>ON CA<br>M5G 2P5 | | | 818,505 | | |
| 2 | Hydro One Inc. | 483 Bay Street<br><br>Toronto<br>ON CA<br>M5G 2P5 | | | 49,336 | | |

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Canada

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**Schedule 15**

# Deferred Income Plans

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

| | Type of plan (see note 1) 100 | Amount of contribution $ (see note 2) 200 | Registration number (RPP, RSUBP, PRPP, and DPSP only) 300 | Name of EPSP trust 400 | Address of EPSP trust 500 | T4PS slip(s) (see note 3) 600 |
|---|---|---|---|---|---|---|
| 1 | 1 | 1,401,481 | 1059104 | | | |

**Note 1**

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

**Note 2**

You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . . . . . . . . . . . . . . . . 1,401,481 A

**Less:**

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 1,401,481 B

**Deductible amount for contributions to deferred income plans**
(amount A **minus** amount B) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . C

Enter amount C on line 417 of Schedule 1

**Note 3**

T4PS slip(s) filed by: 1 – Trustee
2 – Employer
(EPSP only)

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**SCHEDULE 23**

# AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

**Column 1:** Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

**Column 2:** Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

**Column 3:** Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)

2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction

3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)

4 – Associated non-CCPC

5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

**Column 4:** Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

**Column 5:** Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

**Column 6:** Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

| Calendar year | Acceptable range |
|---|---|
| 2006 | maximum $300,000 |
| 2007 | $300,001 to $400,000 |

| Calendar year | Acceptable range |
|---|---|
| 2008 | maximum $400,000 |
| 2009 | $400,001 to $500,000 |

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

## Allocating the business limit

Date filed (do not use this area) . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . **050** Year 2013

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** 1 Yes [ ] 2 No [X]

| | 1 Names of associated corporations 100 | 2 Business Number of associated corporations 200 | 3 Association code 300 | 4 Business limit for the year (before the allocation) $ | 5 Percentage of the business limit % 350 | 6 Business limit allocated* $ 400 |
|---|---|---|---|---|---|---|
| 1 | Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 1 | 500,000 | | |
| 2 | Hydro One Inc. | 86999 4731 RC0001 | 1 | 500,000 | | |
| 3 | Hydro One Networks Inc. | 87086 5821 RC0001 | 1 | 500,000 | 100.0000 | 500,000 |
| 4 | Hydro One Telecom Inc. | 86800 1066 RC0001 | 1 | 500,000 | | |
| 5 | Hydro One Telecom Link Limited | 88786 7513 RC0001 | 1 | 500,000 | | |
| 6 | Hydro One Brampton Networks Inc. | 86486 7635 RC0001 | 1 | 500,000 | | |
| 7 | Hydro One Lake Erie Link Management Inc | 87892 1519 RC0001 | 1 | 500,000 | | |
| 8 | Hydro One Lake Erie Link Company Inc. | 87560 6519 RC0001 | 1 | 500,000 | | |
| 9 | Hydro One B2M LP Inc. | 81838 2046 RC0001 | 1 | 500,000 | | |
| 10 | B2M GP Inc. | 81838 1840 RC0001 | 1 | 500,000 | | |
| 11 | Hydro One B2M Holdings Inc. | 82217 7531 RC0001 | 1 | 500,000 | | |
| 12 | 1908872 Ontario Inc. | 82581 6838 RC0001 | 1 | 500,000 | | |
| 13 | 1908873 Ontario Inc. | 83392 0978 RC0001 | 1 | 500,000 | | |

| | 1 Names of associated corporations 100 | 2 Business Number of associated corporations 200 | 3 Asso-ciation code 300 | 4 Business limit for the year (before the allocation) $ | 5 Percentage of the business limit % 350 | 6 Business limit allocated* $ 400 | |
|---|---|---|---|---|---|---|---|
| 14 | 1893080 Ontario Inc. | 82217 7333 RC0001 | 1 | 500,000 | | | |
| | | | | Total | 100.0000 | 500,000 | A |

**Business limit reduction under subsection 125(5.1) of the ITA**

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

# Summary of Investment Tax Credit Carryovers

## Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

**Current year**

| Addition current year (A) | Applied current year (B) | Claimed as a refund (C) | Carried back (D) | ITC end of year (A-B-C-D) |
|---|---|---|---|---|
| | | | | |

**Prior years**

| Taxation year | ITC beginning of year (E) | Adjustments (F) | Applied current year (G) | ITC end of year (E-F-G) |
|---|---|---|---|---|
| 2012-12-31 | 849 | | | 849 |
| 2011-12-31 | | | | |
| 2010-12-31 | | | | |
| 2009-12-31 | | | | |
| 2008-12-31 | | | | |
| 2007-12-31 | | | | |
| 2006-12-31 | | | | |
| 2005-12-31 | | | | |
| 2004-12-31 | | | | |
| 2003-12-31 | | | | * |
| 2002-12-31 | | | | |
| 2001-12-31 | | | | |
| 2000-12-31 | | | | |
| 1999-12-31 | | | | |
| 1999-03-31 | | | | |
| 1998-03-31 | | | | |
| 1997-03-31 | | | | |
| 1996-03-31 | | | | |
| 1995-03-31 | | | | |
| 1994-03-31 | | | | * |
| **Total** | 849 | | | 849 |

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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**SCHEDULE 50**

## SHAREHOLDER INFORMATION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

| | Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) | Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") | Social insurance number | Trust number | Percentage common shares | Percentage preferred shares |
|---|---|---|---|---|---|---|
| | 100 | 200 | 300 | 350 | 400 | 500 |
| 1 | Hydro One Inc. | 86999 4731 RC0001 | | | 100.000 | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |

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**SCHEDULE 53**

# GENERAL RATE INCOME POOL (GRIP) CALCULATION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

On: 2013-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

## Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

**2006 addition**

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4: 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   **If the answer to question 3 is yes, complete Part "GRIP addition for 2006".**

**Change in the type of corporation**

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   **If the answer to question 5 is yes, complete Part 4.**

**Amalgamation (first year of filing after amalgamation)**

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   **If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.**
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   **If the answer to question 7 is yes, complete Part 4.**
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   **If the answer to question 8 is yes, complete Part 3.**

**Winding-up**

9. Has the corporation wound-up a subsidiary in the preceding taxation year? ☐ Yes ☒ No
   **If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.**
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    **If the answer to question 10 is yes, complete Part 4.**
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    **If the answer to question 11 is yes, complete Part 3.**

## Part 1 – Calculation of general rate income pool (GRIP)

| | | | | |
|---|---|---|---|---|
| GRIP at the end of the previous tax year | | | 100 | 1,223,283 A |
| Taxable income for the year (DICs enter "0") * | | 110 | B | |
| Income for the credit union deduction * (amount E in Part 3 of Schedule 17) | 120 | | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * | 130 | | | |
| For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * | 140 | | | |
| Subtotal (**add** lines 120, 130, and 140) | | ► | C | |
| Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0") | | 150 | | |
| After-tax income (line 150 x general rate factor for the tax year ** 0.72 ) | | | 190 | D |
| Eligible dividends received in the tax year | | 200 | | |
| Dividends deductible under section 113 received in the tax year | | 210 | | |
| Subtotal (**add** lines 200 and 210) | | | ► | E |
| GRIP addition: | | | | |
| Becoming a CCPC (line PP from Part 4) | | 220 | | |
| Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4) | | 230 | | |
| Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4) | | 240 | | |
| Subtotal (**add** lines 220, 230, and 240) | | | ► 290 | F |
| Subtotal (**add** lines A, D, E, and F) | | | | 1,223,283 G |
| Eligible dividends paid in the previous tax year | | 300 | | |
| Excessive eligible dividend designations made in the previous tax year | | 310 | | |

**Note:** If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.

| | | | |
|---|---|---|---|
| Subtotal (line 300 **minus** line 310) | | ► | H |
| GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative) | | 490 | 1,223,283 |
| Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2) | | 560 | 1,503,909 |
| **GRIP at the end of the tax year** (line 490 **minus** line 560) | | 590 | -280,626 |

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

**First previous tax year** 2012-12-31

| | | | |
|---|---|---|---|
| Taxable income before specified future tax consequences from the current tax year | | J1 | |
| Enter the following amounts before specified future tax consequences from the current tax year: | | | |
| Income for the credit union deduction (amount E in Part 3 of Schedule 17) | K1 | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less | L1 | | |
| Aggregate investment income (line 440 of the T2 return) | M1 | | |
| Subtotal (**add** lines K1, L1, and M1) | ► | N1 | |
| Subtotal (line J1 **minus** line N1) (if negative, enter "0") | | ► | O1 |

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

**GRIP adjustment for specified future tax consequences to the first previous tax year**

(line V1 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** ______

**Second previous tax year** 2011-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ M2

Subtotal (**add** lines K2, L2, and M2) ______ ▶ ______ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") ______ ▶ ______ O2

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

**GRIP adjustment for specified future tax consequences to the second previous tax year**

(line V2 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **520** ______

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

**Third previous tax year** 2010-12-31

Taxable income before specified future tax consequences from the current tax year . . . 2,088,762 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ▶ ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 2,088,762 ▶ 2,088,762 O3

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| 2,435,715 | | | | | 2,435,715 |

Taxable income after specified future tax consequences . . . . . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ▶ ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ▶ ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") 2,088,762 V3

**GRIP adjustment for specified future tax consequences to the third previous tax year**
(line V3 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . **540** 1,503,909

**Total GRIP adjustment for specified future tax consequences to previous tax years:**
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . . . . 1,503,909 W

Enter amount W on line 560.

## Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

**nb. 1** Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ▶ ______ DD

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)**
(line AA **minus** line DD) . . . . . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

**nb. 1** Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

| | | | |
|---|---|---|---|
| Cost amount to the corporation of all property immediately before the end of its previous/last tax year | | | FF |
| The corporation's money on hand immediately before the end of its previous/last tax year | | | GG |
| Unused and unexpired losses at the end of the corporation's previous/last tax year: | | | |
| Non-capital losses | | | |
| Net capital losses | | | |
| Farm losses | | | |
| Restricted farm losses | | | |
| Limited partnership losses | | | |
| Subtotal | | ► | HH |
| Subtotal (**add** lines FF, GG, and HH) | | | II |
| All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year | | JJ | |
| Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year | | KK | |
| All the corporation's reserves deducted in its previous/last tax year | | LL | |
| The corporation's capital dividend account immediately before the end of its previous/last tax year | | MM | |
| The corporation's low rate income pool immediately before the end of its previous/last tax year | | NN | |
| Subtotal (**add** lines JJ, KK, LL, MM, and NN) | | ► | OO |
| **GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC** (line II **minus** line OO) (if negative, enter "0") | | | PP |

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

| | | | | | | |
|---|---|---|---|---|---|---|
| 0.68 | x | number of days in the tax year before January 1, 2010 / number of days in the tax year | / 365 | . . . . . . . . . . . | = | QQ |
| 0.69 | x | number of days in the tax year in 2010 / number of days in the tax year | / 365 | . . . . . . . . . . . | = | RR |
| 0.7 | x | number of days in the tax year in 2011 / number of days in the tax year | / 365 | . . . . . . . . . . . | = | SS |
| 0.72 | x | number of days in the tax year after December 31, 2011 / number of days in the tax year | 365 / 365 | . . . . . . . . . . . | = 0.720000000 | TT |

**General rate factor for the tax year** (total of lines QQ to TT) . . . . . . . . . . . . . . . . . . . . . 0.72000 UU

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 510**

# Ontario Corporate Minimum Tax

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Determination of CMT applicability

| | | |
|---|---|---|
| Total assets of the corporation at the end of the tax year * | 112 | 73,695,000 |
| Share of total assets from partnership(s) and joint venture(s) * | 114 | |
| Total assets of associated corporations (amount from line 450 on Schedule 511) | 116 | 33,431,225,104 |
| Total assets (total of lines 112 to 116) | | 33,504,920,104 |
| Total revenue of the corporation for the tax year ** | 142 | 50,035,000 |
| Share of total revenue from partnership(s) and joint venture(s) ** | 144 | |
| Total revenue of associated corporations (amount from line 550 on Schedule 511) | 146 | 6,702,002,000 |
| Total revenue (total of lines 142 to 146) | | 6,752,037,000 |

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

## Part 2 – Adjusted net income/loss for CMT purposes

| | | | | |
|---|---|---|---|---|
| Net income/loss per financial statements * | | | 210 | 13,000 |
| **Add** (to the extent reflected in income/loss): | | | | |
| Provision for current income taxes/cost of current income taxes | 220 | | | |
| Provision for deferred income taxes (debits)/cost of future income taxes | 222 | | | |
| Equity losses from corporations | 224 | | | |
| Financial statement loss from partnerships and joint ventures | 226 | | | |
| Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act | 230 | | | |
| **Other additions** (see note below): | | | | |
| Share of adjusted net income of partnerships and joint ventures ** | 228 | | | |
| Total patronage dividends received, not already included in net income/loss | 232 | | | |
| 281 | 282 | | | |
| 283 | 284 | | | |
| Subtotal | | | | A |
| **Deduct** (to the extent reflected in income/loss): | | | | |
| Provision for recovery of current income taxes/benefit of current income taxes | 320 | 1,091,000 | | |
| Provision for deferred income taxes (credits)/benefit of future income taxes | 322 | | | |
| Equity income from corporations | 324 | | | |
| Financial statement income from partnerships and joint ventures | 326 | | | |
| Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act | 330 | | | |
| Dividends not taxable under section 83 of the federal Act (from Schedule 3) | 332 | | | |
| Gain on donation of listed security or ecological gift | 340 | | | |
| Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act *** | 342 | | | |
| Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act **** | 344 | | | |
| Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act ***** | 346 | | | |
| Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act | 348 | | | |
| **Other deductions** (see note below): | | | | |
| Share of adjusted net loss of partnerships and joint ventures ** | 328 | | | |
| Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3 | 334 | | | |
| Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss | 336 | | | |
| Patronage dividends paid (from Schedule 16) not already included in net income/loss | 338 | | | |
| 381 Other comprehensive income included in income | 382 | 13,000 | | |
| 383 | 384 | | | |
| 385 | 386 | | | |
| 387 | 388 | | | |
| 389 | 390 | | | |
| Subtotal | | 1,104,000 | | 1,104,000 B |
| Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B) | | | 490 | -1,091,000 |

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

**Note**

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

## Part 2 – Adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

## Part 3 – CMT payable

| | | | | |
|---|---|---|---|---|
| Adjusted net income for CMT purposes (line 490 in Part 2, if positive) | | 515 | | |
| **Deduct:** | | | | |
| CMT loss available (amount R from Part 7) | 1,551,765 | | | |
| **Minus:** Adjustment for an acquisition of control * | 518 | | | |
| Adjusted CMT loss available | 1,551,765 ▶ | | 1,551,765 | C |
| Net income subject to CMT calculation (if negative, enter "0") | | 520 | | |

Amount from line 520 ______ x (Number of days in the tax year before July 1, 2010 ______ / Number of days in the tax year 365) x 4 % = ______ 1

Amount from line 520 ______ x (Number of days in the tax year after June 30, 2010 365 / Number of days in the tax year 365) x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ 3

| | | | |
|---|---|---|---|
| Gross CMT: amount on line 3 above x OAF ** | 540 | | |
| **Deduct:** | | | |
| Foreign tax credit for CMT purposes *** | 550 | | |
| CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") | | | D |
| **Deduct:** | | | |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | | |
| Net CMT payable (if negative, enter "0") | | | E |

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

**** Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

**Ontario allocation factor** ........ 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

## Part 4 – CMT credit carryforward

| | | | | |
|---|---|---|---|---|
| CMT credit carryforward at the end of the previous tax year * | | | | G |
| **Deduct:** | | | | |
| CMT credit expired * | 600 | | | |
| CMT credit carryforward at the beginning of the current tax year * (see note below) | | | 620 | |
| **Add:** | | | | |
| CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) | | | 650 | |
| CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) | | | | H |
| **Deduct:** | | | | |
| CMT credit deducted in the current tax year (amount P from Part 5) | | | | I |
| Subtotal (amount H **minus** amount I) | | | | J |
| **Add:** | | | | |
| Net CMT payable (amount E from Part 3) | | | | |
| SAT payable (amount O from Part 6 of Schedule 512) | | | | |
| Subtotal | | | | K |
| CMT credit carryforward at the end of the tax year (amount J **plus** amount K) | | | 670 | L |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

**Note:** If you entered an amount on line 620 or line 650, complete Part 6.

## Part 5 – CMT credit deducted from Ontario corporate income tax payable

| | | | | |
|---|---|---|---|---|
| CMT credit available for the tax year (amount H from Part 4) | | | | M |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | | 1 | |
| For a corporation that is not a life insurance corporation: | | | | |
| CMT after foreign tax credit deduction (amount D from Part 3) | | 2 | | |
| For a life insurance corporation: | | | | |
| Gross CMT (line 540 from Part 3) | | 3 | | |
| Gross SAT (line 460 from Part 6 of Schedule 512) | | 4 | | |
| The **greater** of amounts 3 and 4 | | 5 | | |
| **Deduct:** line 2 or line 5, whichever applies: | | | 6 | |
| Subtotal (if negative, enter "0") | | | | N |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | | | |
| **Deduct:** | | | | |
| Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) | 30,604 | | | |
| Subtotal (if negative, enter "0") | | | | O |
| CMT credit deducted in the current tax year (least of amounts M, N, and O) | | | | P |

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

## Part 6 – CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | CMT credit balance * |
|---|---|
| 10th previous tax year | 680 |
| 9th previous tax year | 681 |
| 8th previous tax year | 682 |
| 7th previous tax year | 683 |
| 6th previous tax year | 684 |
| 5th previous tax year | 685 |
| 4th previous tax year | 686 |
| 3rd previous tax year | 687 |
| 2nd previous tax year | 688 |
| 1st previous tax year | 689 |
| Total ** | |

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

## Part 7 – CMT loss carryforward

| | | | | |
|---|---|---|---|---|
| CMT loss carryforward at the end of the previous tax year * | | 1,551,765 Q | | |
| **Deduct:** | | | | |
| CMT loss expired * | 700 | | | |
| CMT loss carryforward at the beginning of the tax year * (see note below) | | 1,551,765 ▶ | 720 | 1,551,765 |
| **Add:** | | | | |
| CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) | | | 750 | |
| CMT loss available (line 720 **plus** line 750) | | | | 1,551,765 R |
| **Deduct:** | | | | |
| CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) | | | | |
| Subtotal (if negative, enter "0") | | | | 1,551,765 S |
| **Add:** | | | | |
| Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) | | | 760 | 1,091,000 |
| CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) | | | 770 | 2,642,765 T |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

**Note:** If you entered an amount on line 720 or line 750, complete Part 8.

## Part 8 – CMT loss available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | Balance earned in a tax year ending before March 23, 2007 * | Balance earned in a tax year ending after March 22, 2007 ** |
|---|---|---|
| 10th previous tax year | 810 | 820 |
| 9th previous tax year | 811 | 821 |
| 8th previous tax year | 812 | 822 |
| 7th previous tax year | 813 | 823 |
| 6th previous tax year | 814 | 824 |
| 5th previous tax year | 815 | 825 |
| 4th previous tax year | 816 | 826 |
| 3rd previous tax year | 817 | 827 |
| 2nd previous tax year | 818 | 828 |
| 1st previous tax year | | 829 |
| Total *** | | |

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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**SCHEDULE 511**

# ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return*.

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 1 | Hydro One Inc. | 86999 4731 RC0001 | 13,247,000,000 | 650,000,000 |
| 2 | Hydro One Networks Inc. | 87086 5821 RC0001 | 19,698,000,000 | 5,502,000,000 |
| 3 | Hydro One Telecom Inc. | 86800 1066 RC0001 | 76,876,000 | 80,880,000 |
| 4 | Hydro One Telecom Link Limited | 88786 7513 RC0001 | 1,111,000 | 442,000 |
| 5 | Hydro One Brampton Networks Inc. | 86486 7635 RC0001 | 403,229,000 | 468,680,000 |
| 6 | Hydro One Lake Erie Link Management Inc | 87892 1519 RC0001 | 4,990,000 | 0 |
| 7 | Hydro One Lake Erie Link Company Inc. | 87560 6519 RC0001 | 18,000 | 0 |
| 8 | Hydro One B2M LP Inc. | 81838 2046 RC0001 | 1 | 0 |
| 9 | B2M GP Inc. | 81838 1840 RC0001 | 999 | 0 |
| 10 | Hydro One B2M Holdings Inc. | 82217 7531 RC0001 | 100 | 0 |
| 11 | 1908872 Ontario Inc. | 82581 6838 RC0001 | 1 | 0 |
| 12 | 1908873 Ontario Inc. | 83392 0978 RC0001 | 1 | 0 |
| 13 | 1893080 Ontario Inc. | 82217 7333 RC0001 | 2 | 0 |
| | | **Total** | 450 33,431,225,104 | 550 6,702,002,000 |

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511

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**SCHEDULE 546**

# *CORPORATIONS INFORMATION ACT* ANNUAL RETURN FOR ONTARIO CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

## Part 1 – Identification

**100** Corporation's name (exactly as shown on the MGS public record)
Hydro One Remote Communities Inc.

| Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent | **110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day) | **120** Ontario Corporation No. |
|---|---|---|
| Ontario | 1998-08-18 | 1310735 |

## Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

**200** Care of (if applicable)

| **210** Street number | **220** Street name/Rural route/Lot and Concession number | **230** Suite number |
|---|---|---|
| 483 | Bay Street 8th Floor | |

**240** Additional address information if applicable (line 220 must be completed first)
South Tower

| **250** Municipality (e.g., city, town) | **260** Province/state | **270** Country | **280** Postal/zip code |
|---|---|---|---|
| Toronto | ON | CA | M5G 2P5 |

## Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

**300** [ 1 ] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

## Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

**450** BARAGETTI (Last name) **451** GIOVANNA (First name)

**454** ______________________, (Middle name(s))

**460** [ 3 ] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

**Complete the applicable parts to report changes in the information recorded on the MGS public record.**

## Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | 530 Street name/Rural route/Lot and Concession number | 540 Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | 570 Province/state | 580 Country | 590 Postal/zip code

## Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

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**SCHEDULE 550**

# ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return.*
- File this schedule with the *T2 Corporation Income Tax Return.*

## Part 1 – Corporate information

| 110 Name of person to contact for more information | 120 Telephone number including area code |
|---|---|
| SELMA YAM | (416) 345-6827 |

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

## Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 9,723,581

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

| | A<br>Name of university, college, or other eligible educational institution<br>**400** | B<br>Name of qualifying co-operative education program<br>**405** |
|---|---|---|
| 1. | Carelton | Mechanical Engineering |
| 2. | Carelton | Mechanical Engineering |
| 3. | Toronto | Mechanical Engineering |
| 4. | Toronto | Mechanical Engineering |
| 5. | | |

| | C<br>Name of student<br>**410** | D<br>Start date of WP (see note 1 below)<br>**430** | E<br>End date of WP (see note 2 below)<br>**435** |
|---|---|---|---|
| 1. | [redacted] | 2013-05-06 | 2013-08-31 |
| 2. | | 2013-09-01 | 2013-12-31 |
| 3. | | 2013-01-01 | 2013-04-30 |
| 4. | | 2013-05-07 | 2013-08-22 |
| 5. | | | |

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

## Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

| | F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450 | Eligible percentage before March 27, 2009 (from line 310 in Part 3) | F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452 | Eligible percentage after March 26, 2009 (from line 310a in Part 3) | X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below) | Y Total number of consecutive weeks of the student's WP (see note 3 below) |
|---|---|---|---|---|---|---|
| 1. | | 10.000 % | 17,739 | 25.000 % | | 17 |
| 2. | | 10.000 % | 17,739 | 25.000 % | | 17 |
| 3. | | 10.000 % | 22,861 | 25.000 % | | 16 |
| 4. | | 10.000 % | 22,861 | 25.000 % | | 14 |
| 5. | | 10.000 % | | 25.000 % | | |

| | G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460 | H Maximum CETC per WP (see note 3 below) 462 | I CETC on eligible expenditures (column G or H, whichever is less) 470 | J CETC on repayment of government assistance (see note 4 below) 480 | K CETC for each WP (column I or column J) 490 |
|---|---|---|---|---|---|
| 1. | 4,435 | 3,000 | 3,000 | | 3,000 |
| 2. | 4,435 | 3,000 | 3,000 | | 3,000 |
| 3. | 5,715 | 3,000 | 3,000 | | 3,000 |
| 4. | 5,715 | 3,000 | 3,000 | | 3,000 |
| 5. | | | | | |

**Ontario co-operative education tax credit** (total of amounts in column K) 500 12,000 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = . . . . . . . . . . . . . . . . . . . . . . ______ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations.* If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency | Agence du revenu du Canada

**SCHEDULE 552**

# ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2013-12-31 |

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act.*
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return.*
- File this schedule with your *T2 Corporation Income Tax Return.*

## Part 1 – Corporate information (please print)

| **110** Name of person to contact for more information | **120** Telephone number including area code |
|---|---|
| SELMA YAM | (416) 345-6827 |

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

## Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 9,723,581

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[ 5\,\% \times \frac{(\text{amount on line 300} \text{ minus } 400{,}000)}{200{,}000} \right]$$

**Specified percentage** . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[ 10\,\% \times \frac{(\text{amount on line 300} \text{ minus } 400{,}000)}{200{,}000} \right]$$

**Specified percentage** . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

| | A<br>Trade code<br>**400** | B<br>Apprenticeship program/ trade name<br>**405** | C<br>Name of apprentice<br>**410** |
|---|---|---|---|
| 1. | 310t | Truck And Coach Technician | [redacted] |
| 2. | 310t | Truck And Coach Technician | |
| 3. | 310t | Truck And Coach Technician | |
| 4. | 310t | Truck And Coach Technician | |
| 5. | 434a | Powerline Technician | |
| 6. | 434a | Powerline Technician | |
| 7. | | | |

| | D<br>Original contract or training agreement number<br>**420** | E<br>Original registration date of apprenticeship contract or training agreement (see note 1 below)<br>**425** | F<br>Start date of employment as an apprentice in the tax year (see note 2 below)<br>**430** | G<br>End date of employment as an apprentice in the tax year (see note 3 below)<br>**435** |
|---|---|---|---|---|
| 1. | [redacted] | 2009-01-05 | 2013-01-01 | 2013-01-05 |
| 2. | | 2009-08-17 | 2013-01-02 | 2013-03-14 |
| 3. | | 2011-05-30 | 2013-10-28 | 2013-12-19 |
| 4. | | 2010-07-05 | 2013-03-06 | 2013-09-27 |
| 5. | | 2010-05-03 | 2013-07-22 | 2013-12-31 |
| 6. | | 2011-03-28 | 2013-01-21 | 2013-07-19 |

| | D<br>Original contract or training agreement number<br>420 | E<br>Original registration date of apprenticeship contract or training agreement<br>(see note 1 below)<br>425 | F<br>Start date of employment as an apprentice in the tax year<br>(see note 2 below)<br>430 | G<br>End date of employment as an apprentice in the tax year<br>(see note 3 below)<br>435 |
|---|---|---|---|---|
| 7. | | | | |

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

## Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

| | H1<br>Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below)<br>441 | H2<br>Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below)<br>442 | H3<br>Number of days employed as an apprentice in the tax year (column H1 **plus** column H2)<br>440 | I<br>Maximum credit amount for the tax year (see note 2 below)<br>445 |
|---|---|---|---|---|
| 1. | | 5 | 5 | 137 |
| 2. | | 72 | 72 | 1,973 |
| 3. | | 53 | 53 | 1,452 |
| 4. | | 206 | 206 | 5,644 |
| 5. | | 163 | 163 | 4,466 |
| 6. | | 180 | 180 | 4,932 |
| 7. | | | | |

| | J1<br>Eligible expenditures before March 27, 2009 (see note 3 below)<br>451 | J2<br>Eligible expenditures after March 26, 2009 (see note 3 below)<br>452 | J3<br>Eligible expenditures for the tax year (column J1 **plus** column J2)<br>450 | K<br>Eligible expenditures **multiplied** by specified percentage (see note 4 below)<br>460 |
|---|---|---|---|---|
| 1. | | 93,336 | 93,336 | 32,668 |
| 2. | | 92,676 | 92,676 | 32,437 |
| 3. | | 64,434 | 64,434 | 22,552 |
| 4. | | 89,190 | 89,190 | 31,217 |
| 5. | | 103,175 | 103,175 | 36,111 |
| 6. | | 93,143 | 93,143 | 32,600 |
| 7. | | | | |

| | L<br>ATTC on eligible expenditures (lesser of columns I and K)<br>470 | M<br>ATTC on repayment of government assistance (see note 5 below)<br>480 | N<br>ATTC for each apprentice (column L or column M, whichever applies)<br>490 |
|---|---|---|---|
| 1. | 137 | | 137 |
| 2. | 1,973 | | 1,973 |
| 3. | 1,452 | | 1,452 |
| 4. | 5,644 | | 5,644 |
| 5. | 4,466 | | 4,466 |
| 6. | 4,932 | | 4,932 |
| 7. | | | |

**Ontario apprenticeship training tax credit** (total of amounts in column N) 500 18,604 O or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ________ % = . . . . . . . . . . . . . . . . ________ P

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations.* If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

200

Canada Revenue Agency — Agence du revenu du Canada

# T2 Corporation Income Tax Return

055 Do not use this area

Filed: 2017-08-28
EB-2017-0051
Exhibit D2-09-01
Attachment 2
Page 1 of 100

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

## Identification

**Business number (BN)** . . . . . . . . . . 001 87083 6269 RC0001

**Corporation's name**
002 Hydro One Remote Communities Inc.

**Address of head office**
Has this address changed since the last time we were notified? . . . . . . . . . . . . 010 1 Yes [X] 2 No [ ]
(If **yes**, complete lines 011 to 018.)
011 680 Beaverhall Place
012
City: 015 Thunder Bay
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 P7E 6G9

**Mailing address** (if different from head office address)
Has this address changed since the last time we were notified? . . . . . . . . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o Selma Yam
022 483 Bay Street 7th Floor
023 South Tower
City: 025 Toronto
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal code/Zip code: 028 M5G 2P5

**Location of books and records** (if different from head office address)
Has the location of books and records changed since the last time we were notified? . . . . . . . . . . . . . . . . . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 483 Bay Street 7th Floor
032 South Tower
City: 035 Toronto
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 M5G 2P5

**040 Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . . . . . . . . . . 043 ____ YYYY MM DD

**To which tax year does this return apply?**
Tax year start 060 2014-01-01 (YYYY MM DD)
Tax year-end 061 2014-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . . . . . 063 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired . . . . . . . . . . . . . 065 ____ YYYY MM DD

**Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)?** . . . . . . . . . . . 066 1 Yes [ ] 2 No [X]

**Is the corporation a professional corporation that is a member of a partnership?** . . . . . . . . . . . . . . . . . 067 1 Yes [ ] 2 No [X]

**Is this the first year of filing after:**
Incorporation? . . . . . . . . . . . . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . . . . . . . . . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . 076 1 Yes [ ] 2 No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . 078 1 Yes [ ] 2 No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . 079 ____

**Is the corporation a resident of Canada?**
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ____

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

**Do not use this area**
095 ____ 096 ____

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| Is the corporation an associated CCPC? | 160 | X | 23 |
| Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders who own voting shares? | 151 | | 19 |
| Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | X | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | X | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership account number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation own any shares in one or more foreign affiliates in the tax year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*? | 170 | | 29 |
| Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | X | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | ——— |
| Does the corporation earn income from one or more Internet webpages or websites? | 180 | X | 88 |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine? | 202 | | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | | 3 |
| Is the corporation claiming any type of losses? | 204 | X | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | X | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | | 6 |
| i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440? | 207 | | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any property that is eligible capital property? | 210 | | 10 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)? | 213 | | 13 |
| Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits? | 221 | | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | X | 31 |
| Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | | 33/34/35 |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | | ——— |
| Is the corporation claiming a surtax credit? | 237 | | 37 |
| Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II - Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit refund? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit refund? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments – continued from page 2

| | | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates in the tax year? | 271 | | T1134 |
| Did the corporation own specified foreign property in the year with a cost amount over $100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | 262 | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| | | | |
|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | 1 Yes | 2 No X |
| Is the corporation inactive? | 280 | 1 Yes | 2 No X |

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

| | | | |
|---|---|---|---|
| 284 | Electricity generation and distribution | 285 | 100.000 % |
| 286 | | 287 | % |
| 288 | | 289 | % |

| | | | |
|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | 1 Yes | 2 No X |
| Did the corporation emigrate from Canada during the tax year? | 292 | 1 Yes | 2 No X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | 1 Yes | 2 No |
| If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible | 294 | YYYY MM DD | |
| If the corporation's major business activity is construction, did you have any subcontractors during the tax year? | 295 | 1 Yes | 2 No |

## Taxable income

| | | | | |
|---|---|---|---|---|
| Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. | 300 | | -2,858,863 | A |
| **Deduct:** Charitable donations from Schedule 2 | 311 | | | |
| Gifts to Canada, a province, or a territory from Schedule 2 | 312 | | | |
| Cultural gifts from Schedule 2 | 313 | | | |
| Ecological gifts from Schedule 2 | 314 | | | |
| Gifts of medicine from Schedule 2 | 315 | | | |
| Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | | | |
| Part VI.1 tax deduction* | 325 | | | |
| Non-capital losses of previous tax years from Schedule 4 | 331 | | | |
| Net capital losses of previous tax years from Schedule 4 | 332 | | | |
| Restricted farm losses of previous tax years from Schedule 4 | 333 | | | |
| Farm losses of previous tax years from Schedule 4 | 334 | | | |
| Limited partnership losses of previous tax years from Schedule 4 | 335 | | | |
| Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | |
| Prospector's and grubstaker's shares | 350 | | | |
| Subtotal | | | | B |
| Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | | C |
| **Add:** Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | 355 | | | D |
| **Taxable income** (amount C **plus** amount D) | 360 | | | |
| Income exempt under paragraph 149(1)(t) | 370 | | | |
| **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | | Z |

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

Income from active business carried on in Canada from Schedule 7 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **400** ________ A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7,
**minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of
federal law, is exempt from Part I tax . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **405** ________ B

Business limit (see notes 1 and 2 below) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **410** ________ C

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction:**

Amount C ________ x **415** *** ________ / 11,250 D = . . . . . . . . . . . . . . . . . . . . . . . . ________ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **425** ________ F

**Small business deduction**

Amount A, B, C, or F, whichever is the least ________ x 17 % = . . . . . . . . . . . . . . . . . . . . . . . **430** ________ G

Enter amount G on line I on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | A |
| Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 | | | B | |
| Amount QQ from Part 13 of Schedule 27 | | | C | |
| Personal service business income | 432 | | D | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | | E | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | | F | |
| Aggregate investment income from line 440 on page 6* | | | G | |
| Subtotal (**add** amounts B to G) | | | | H |
| Amount A **minus** amount H (if negative, enter "0") | | | | I |
| **General tax reduction for Canadian-controlled private corporations** – Amount I **multiplied** by | 13 % | | | J |

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | K |
| Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 | | | L | |
| Amount QQ from Part 13 of Schedule 27 | | | M | |
| Personal service business income | 434 | | N | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | | O | |
| Subtotal (**add** amounts L to O) | | | | P |
| Amount K **minus** amount P (if negative, enter "0") | | | | Q |
| **General tax reduction** – Amount Q **multiplied** by | 13 % | | | R |

Enter amount R on line 639 on page 7.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

Aggregate investment income from Schedule 7 . . . . . . . . **440** ______ x 26 2 / 3 % = . . . . . . . . . . . . . . . . ______ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . . . . . . . . . . . . . . . . . . ______ B

**Deduct:**
Foreign investment income from Schedule 7 . . . . . . . . . . **445** ______ x 9 1 / 3 % = ______ C
(if negative, enter "0") ______ ______ D

Amount A **minus** amount D (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ E

Taxable income from line 360 on page 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ F

**Deduct:**
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ G
Foreign non-business income tax credit from line 632 on page 7 . . . ______ x 100 / 35 = ______ H
Foreign business income tax credit from line 636 on page 7 . . . . . . . . . . . . . ______ x 4 = ______ I
Subtotal ______ ______ J
______ K
x 26 2 / 3 % = ______ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . . . . . . . . . . . . . . . . . . ______ M

**Refundable portion of Part I tax** – Amount E, L, or M, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **450** ______ N

## Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . . . . . . . . . . . . . . **460** ______
**Deduct:** Dividend refund for the previous tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **465** ______
______ ______ O

**Add** the total of:
Refundable portion of Part I tax from line 450 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ P
Total Part IV tax payable from Schedule 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ Q
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . . . . . . . . . . . . . . . . . . . . **480** ______
______ ______ R

**Refundable dividend tax on hand at the end of the tax year** – Amount O **plus** amount R . . . . . . . . . . . . . . . . . . . . **485** ______

## Dividend refund

**Private and subject corporations at the time taxable dividends were paid in the tax year**

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . . . . . . ______ x 1 / 3 = ______ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ T

**Dividend refund** – Amount S or T, whichever is less . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ U
Enter amount U on line 784 on page 8.

## Part I tax

| | | | | | |
|---|---|---|---|---|---|
| **Base amount Part I tax** – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % | | | **550** | | A |
| **Recapture of investment tax credit from Schedule 31** | | | **602** | | B |

**Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income**
(if it was a CCPC throughout the tax year)

| | | | | |
|---|---|---|---|---|
| Aggregate investment income from line 440 on page 6 | | | | C |
| Taxable income from line 360 on page 3 | | D | | |
| **Deduct:** Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | E | | |
| Net amount (amount D **minus** amount E) | | | | F |

| | | | |
|---|---|---|---|
| **Refundable tax on CCPC's investment income** – 6 2 / 3 % of whichever is less: amount C or amount F | **604** | | G |
| Subtotal (**add** amounts A, B, and G) | | | H |

**Deduct:**

| | | | | |
|---|---|---|---|---|
| Small business deduction from line 430 on page 4 | | | I | |
| Federal tax abatement | **608** | | | |
| Manufacturing and processing profits deduction from Schedule 27 | **616** | | | |
| Investment corporation deduction | **620** | | | |
| Taxed capital gains **624** | | | | |
| Additional deduction – credit unions from Schedule 17 | **628** | | | |
| Federal foreign non-business income tax credit from Schedule 21 | **632** | | | |
| Federal foreign business income tax credit from Schedule 21 | **636** | | | |
| General tax reduction for CCPCs from amount J on page 5 | **638** | | | |
| General tax reduction from amount R on page 5 | **639** | | | |
| Federal logging tax credit from Schedule 21 | **640** | | | |
| Eligible Canadian bank deduction under section 125.21 | **641** | | | |
| Federal qualifying environmental trust tax credit | **648** | | | |
| Investment tax credit from Schedule 31 | **652** | | | |
| Subtotal | | | | J |

| | | |
|---|---|---|
| **Part I tax payable** – Amount H **minus** amount J | | K |

Enter amount K on line 700 on page 8.

## Summary of tax and credits

**Federal tax**

| | | |
|---|---|---|
| Part I tax payable from amount K on page 7 | 700 | |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction ... 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | | |
|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | |
| Provincial tax on large corporations (Nova Scotia Schedule 342) | 765 | |

(The Nova Scotia tax on large corporations is eliminated effective July 1, 2012.)

Total provincial or territorial tax ▶

**Deduct other credits:** Total tax payable 770 ______ A

| | | |
|---|---|---|
| Investment tax credit refund from Schedule 31 | 780 | |
| Dividend refund from amount U on page 6 | 784 | |
| Federal capital gains refund from Schedule 18 | 788 | |
| Federal qualifying environmental trust tax credit refund | 792 | |
| Canadian film or video production tax credit refund (Form T1131) | 796 | |
| Film or video production services tax credit refund (Form T1177) | 797 | |
| Tax withheld at source | 800 | |
| Total payments on which tax has been withheld | 801 | |
| Provincial and territorial capital gains refund from Schedule 18 | 808 | |
| Provincial and territorial refundable tax credits from Schedule 5 | 812 | 55,644 |
| Tax instalments paid | 840 | |
| Total credits | 890 | 55,644 ▶ 55,644 B |

Refund code 894 2 Overpayment 55,644

Balance (amount A **minus** amount B) -55,644

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid ......

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

Enclosed payment 898

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? ... 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number ... 920

## Certification

I, 950 BARAGETTI (Last name (print)) 951 GIOVANNA (First name (print)) 954 Vice President, Corporate Tax (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2015-06-29 — Date (yyyy/mm/dd)
Signature of the authorized signing officer of the corporation
956 (416) 345-6778 — Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below ... 957 1 Yes ☐ 2 No ☒

958 SELMA YAM — Name (print)
959 (416) 345-6827 — Telephone number

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

# HYDRO ONE REMOTE COMMUNITIES INC.

## FINANCIAL STATEMENTS

## DECEMBER 31, 2014

**HYDRO ONE REMOTE COMMUNITIES INC.**
**INDEPENDENT AUDITORS' REPORT**

To Directors of Hydro One Remote Communities Inc.

We have audited the accompanying financial statements of Hydro One Remote Communities Inc., which comprise the balance sheet as at December 31, 2014, the statements of operations and comprehensive income, changes in shareholder's deficit and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these 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 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 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 Hydro One Remote Communities Inc. as at December 31, 2014, and its results of operations and its cash flows for the year then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
March 24, 2015

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**
**For the years ended December 31, 2014 and 2013**

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Revenues** *(Note 15)* | 52,130 | 50,035 |
| **Costs** | | |
| Operation, maintenance and administration *(Note 15)* | 20,069 | 19,645 |
| Fuel used for electric generation | 25,869 | 25,568 |
| Depreciation and amortization *(Note 4)* | 4,623 | 4,809 |
| | 50,561 | 50,022 |
| **Income (loss) before financing charges and recovery of payments in lieu of corporate income taxes** | 1,569 | 13 |
| Financing charges *(Notes 5, 15)* | 1,559 | 1,104 |
| **Income before recovery of payments in lieu of corporate income taxes** | 10 | (1,091) |
| Provision for (recovery of) payments in lieu of corporate income taxes *(Notes 6, 15)* | 10 | (1,091) |
| **Net income** | – | – |
| Other comprehensive income | 13 | 13 |
| **Comprehensive income** | 13 | 13 |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS**
**At December 31, 2014 and 2013**

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Accounts receivable (net of allowance for doubtful accounts – $145; 2013 – $296) *(Notes 7, 15)* | 4,454 | 4,995 |
| Regulatory assets *(Note 9)* | 1,301 | 2,427 |
| Fuel, materials and supplies | 2,092 | 1,736 |
| Deferred income tax assets *(Note 6)* | 120 | 108 |
| Income tax receivable *(Notes 6, 15)* | 2,683 | 2,697 |
| | 10,650 | 11,963 |
| Property, plant and equipment *(Note 8)*: | | |
| Property, plant and equipment in service | 63,601 | 58,905 |
| Less: accumulated depreciation | 24,588 | 23,256 |
| | 39,013 | 35,649 |
| Construction in progress | 2,138 | 3,473 |
| Future use components and spares | 1,767 | 1,650 |
| | 42,918 | 40,772 |
| Other long-term assets: | | |
| Regulatory assets *(Note 9)* | 18,283 | 15,923 |
| Deferred income tax assets *(Note 6)* | 4,213 | 4,239 |
| Deferred debt issuance costs *(Note 10)* | 183 | 124 |
| Long-term accounts receivable (net of allowance for doubtful accounts – $159; 2013 – $0) *(Note 7)* | 1,250 | 674 |
| | 23,929 | 20,960 |
| **Total assets** | 77,497 | 73,695 |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**BALANCE SHEETS (continued)**
**At December 31, 2014 and 2013**

| *December 31 (thousands of Canadian dollars, except number of shares)* | **2014** | **2013** |
|---|---|---|
| **Liabilities** | | |
| Current liabilities: | | |
| Inter-company demand facility *(Notes 11, 15)* | 6,806 | 18,031 |
| Accounts payable | 876 | 703 |
| Accrued liabilities *(Notes 12, 13)* | 8,936 | 4,954 |
| Accrued interest *(Note 15)* | 172 | 142 |
| Regulatory liabilities *(Note 9)* | 120 | 109 |
| | 16,910 | 23,939 |
| Long-term debt *(Notes 10, 11, 15)* | 33,000 | 23,000 |
| Other long-term liabilities: | | |
| Post-retirement and post-employment benefit liability *(Note 12)* | 12,862 | 12,088 |
| Regulatory liabilities *(Note 9)* | 4,213 | 4,238 |
| Environmental liabilities *(Note 13)* | 11,068 | 10,999 |
| | 28,143 | 27,325 |
| **Total liabilities** | 78,053 | 74,264 |
| *Contingencies and commitments (Notes 17, 18)* | | |
| **Shareholder's deficit** | | |
| Common shares (authorized: unlimited; issued: 2) *(Note 14)* | – | – |
| Accumulated other comprehensive loss | (556) | (569) |
| **Total shareholder's deficit** | (556) | (569) |
| **Total liabilities and shareholder's deficit** | 77,497 | 73,695 |

*See accompanying notes to Financial Statements.*

On behalf of the Board of Directors:

Carmine Marcello
Chair

Lee Ann Cameron
Director

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CHANGES IN SHAREHOLDER'S DEFICIT**
**For the years ended December 31, 2014 and 2013**

| *Year ended December 31, 2014* *(thousands of Canadian dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2014 | – | (569) | (569) |
| Other comprehensive income | – | 13 | 13 |
| **December 31, 2014** | – | (556) | (556) |

| *Year ended December 31, 2013* *(thousands of Canadian dollars)* | Common shares | Accumulated other comprehensive loss | Total shareholder's deficit |
|---|---|---|---|
| January 1, 2013 | – | (582) | (582) |
| Other comprehensive income | – | 13 | 13 |
| **December 31, 2013** | – | (569) | (569) |

*See accompanying notes to Financial Statements.*

**HYDRO ONE REMOTE COMMUNITIES INC.**
**STATEMENTS OF CASH FLOWS**
**For the years ended December 31, 2014 and 2013**

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Operating activities** | | |
| Net income | – | – |
| Environmental expenditures | (1,598) | (1,656) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (excluding removal costs) | 4,193 | 4,220 |
| Regulatory assets and liabilities | (2,594) | (1,126) |
| Amortization of hedging losses | 13 | 13 |
| Amortization of deferred debt costs and debt discounts | 3 | 3 |
| Changes in non-cash balances related to operations *(Note 16)* | 6,007 | (2,773) |
| **Net cash from (used in) operating activities** | 6,024 | (1,319) |
| | | |
| **Financing activities** | | |
| Long-term debt issued | 10,000 | – |
| Other | (60) | – |
| **Net cash from financing activities** | 9,940 | – |
| | | |
| **Investing activities** | | |
| Capital expenditures | (4,634) | (5,427) |
| Proceeds on disposition of property, plant and equipment | 12 | 4 |
| Future use assets | (117) | (77) |
| **Net cash used in investing activities** | (4,739) | (5,500) |
| | | |
| **Net change in inter-company demand facility** | 11,225 | (6,819) |
| Inter-company demand facility, beginning of year | (18,031) | (11,212) |
| **Inter-company demand facility, end of year** | (6,806) | (18,031) |

*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 Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario), and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The Company uses a cost recovery model applied to achieve breakeven net income and the financial statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2014 have been prepared and are publicly available.

Hydro One Remote Communities 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. No such events or transactions were identified.

### Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairment, contingencies, unbilled revenue, allowance for doubtful accounts 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

In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 distribution rates, seeking approval for a rate increase of approximately 0.48%. On March 13, 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.

In 2012, Hydro One Remote Communities filed a cost-of-service application for 2013 distribution rates. The application requested an increase of 3.45% to customer rates for generation and distribution and an increase of approximately $7 million to annual Rural and Remote Rate Protection (RRRP). In 2013, the OEB approved the proposed rate increase and annual RRRP of approximately $32 million.

### Regulatory Accounting

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

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of the recovery of / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in RRRP amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

### Revenue Recognition

Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues attributable to the generation and 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 RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

### Accounts Receivable and Allowance for Doubtful Accounts

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

Long-term accounts receivable are recorded at their invoiced amount and represent amounts due from specified First Nations. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. Provision for uncollectible amounts for this component is set at the inception of the balance and is maintained until settlement of those amounts. The provision for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts

receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

**Corporate Income Taxes**

Under the *Electricity Act, 1998,* Hydro One Remote Communities is required to make (recover) PILs to (from) 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 recovery of or 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 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.

**Inter-company Demand Facility**

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and

withdrawals made by the Company to and from the pooled cash 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%.

**Fuel, Materials and Supplies**

Fuel is used in the generation of electricity. 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

***Generation***

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

***Distribution***

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

***Administration and Service***

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

**Capitalized Financing Costs**

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 in Progress**

Construction 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**

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category.

The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 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 |
|---|---|---|---|
| Generation | 22 years | 3% – 7% | 5% |
| Distribution | 48 years | 1% – 7% | 2% |
| Administration and service | 45 years | 2% – 20% | 4% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 assets where no asset retirement obligation 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 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. As at December 31, 2014, no asset impairment had been recorded.

**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 Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents OCI and net income 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.

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 11 – Fair Value of Financial Instruments and Risk Management.

Transaction costs associated with financial assets and liabilities that are designated as held-for-trading are recognized immediately in results of operations. All financial instrument transactions are recorded at trade date.

**Derivative Instruments and Hedge Accounting**

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2014. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

**Employee Future Benefits**

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's 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 plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets 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 all 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, including Hydro One Remote Communities, but not including Hydro One Brampton Inc and Norfolk Power Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit 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***

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of the these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for

purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's 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 accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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 Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its 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. 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 Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement 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 Remote Communities records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

## 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 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 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 financial statements.

## 4. DEPRECIATION AND AMORTIZATION

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Depreciation of property, plant and equipment | 2,594 | 2,564 |
| Asset removal costs | 430 | 589 |
| Amortization of regulatory assets | 1,599 | 1,656 |
| | 4,623 | 4,809 |

## 5. FINANCING CHARGES

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Interest on long-term debt | 1,477 | 1,237 |
| Interest on inter-company demand facility | 187 | 216 |
| Amortization of hedging losses | 13 | 13 |
| Other | 28 | 14 |
| Less: Interest capitalized on construction in progress | (146) | (376) |
| | 1,559 | 1,104 |

## 6. PROVISION FOR PILS

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 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Income (loss) before provision for (recovery of) PILs | 10 | (1,091) |
| Canadian Federal and Ontario statutory income tax rate | 26.50% | 26.50% |
| Provision for (recovery of) PILs at statutory rate | 3 | (289) |
| | | |
| Increase (decrease) resulting from: | | |
| | | |
| Net temporary differences included in amounts charged to customers: | | |
| RRPR variance account | (687) | (318) |
| Environmental expenditures | (424) | (439) |
| Pension contribution in excess of pension expense | (132) | (90) |
| Overheads capitalized for accounting but deducted for tax purposes | (93) | (82) |
| Interest capitalized for accounting but deducted for tax purposes | (39) | (100) |
| Losses carryforward | 846 | – |
| Depreciation and amortization in excess of capital cost allowance | 338 | 469 |
| Post-retirement and post-employment benefit expense in excess of cash payments | 189 | 135 |
| Other | – | 56 |
| Net temporary differences | (2) | (369) |
| Prior year adjustments | 10 | (332) |
| Rate difference on loss carryback | – | (110) |
| Other permanent differences | (1) | 9 |
| Total provision for (recovery of) PILs | 10 | (1,091) |
| | | |
| Current provision for (recovery of) PILs | 10 | (1,091) |
| Deferred provision for (recovery of) PILs | – | – |
| Total provision for (recovery of) PILs | 10 | (1,091) |
| | | |
| Effective income tax rate | 100% | 100% |

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2014, the amount receivable from the OEFC was $2,683 thousand (2013 – $2,697 thousand).

### Deferred Income Tax Assets

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, 2014 and 2013, deferred income tax assets and liabilities consisted of the following:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Deferred income tax assets** | | |
| Post-retirement and post-employment benefits expense in excess of cash payments | 4,762 | 4,466 |
| Environmental expenditures | 4,459 | 4,840 |
| Depreciation and amortization in excess of capital cost allowance | 1,231 | 1,845 |
| Non capital losses | 1,183 | – |
| Regulatory amounts not recognized for tax | (7,060) | (6,615) |
| Other | (242) | (189) |
| Total deferred income tax assets | 4,333 | 4,347 |
| Less: current portion | 120 | 108 |
| | 4,213 | 4,239 |

During 2014 and 2013, there was no change in the rate applicable to future taxes.

## 7. ACCOUNTS RECEIVABLE

| *December 31 (thousands of Canadian dollars)* | Current accounts receivable | Long-term accounts receivable | Total |
|---|---|---|---|
| **2014** | | | |
| Accounts receivable – billed | 3,214 | 1,409 | 4,623 |
| Accounts receivable – unbilled | 1,385 | – | 1,385 |
| Accounts receivable, gross | 4,599 | 1,409 | 6,008 |
| Allowance for doubtful accounts | (145) | (159) | (304) |
| Accounts receivable, net | 4,454 | 1,250 | 5,704 |
| | | | |
| **2013** | | | |
| Accounts receivable – billed | 3,887 | 674 | 4,561 |
| Accounts receivable – unbilled | 1,404 | – | 1,404 |
| Accounts receivable, gross | 5,291 | 674 | 5,965 |
| Allowance for doubtful accounts | (296) | – | (296) |
| Accounts receivable, net | 4,995 | 674 | 5,669 |

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2014 and 2013:

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Allowance for doubtful accounts – January 1 | (296) | (302) |
| Write-offs | 77 | 95 |
| Adjustments to allowance for doubtful accounts | (85) | (89) |
| Allowance for doubtful accounts – December 31 | (304) | (296) |

## 8. PROPERTY, PLANT AND EQUIPMENT

| *December 31 (thousands of Canadian dollars)* | Costs | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| **2014** | | | | |
| Generation | 44,770 | 20,385 | 1,742 | 26,127 |
| Distribution | 9,488 | 1,906 | 99 | 7,681 |
| Administration and Service | 11,110 | 2,297 | 297 | 9,110 |
| | 65,368 | 24,588 | 2,138 | 42,918 |
| **2013** | | | | |
| Generation | 41,616 | 19,517 | 2,716 | 24,815 |
| Distribution | 8,394 | 1,748 | 596 | 7,242 |
| Administration and Service | 10,545 | 1,991 | 161 | 8,715 |
| | 60,555 | 23,256 | 3,473 | 40,772 |

Financing charges capitalized on property, plant and equipment under construction were $146 thousand in 2014 (2013 – $376 thousand).

## 9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| **Regulatory assets:** | | |
| Environmental | 12,369 | 13,426 |
| RRPR variance account | 4,578 | 1,985 |
| Post-retirement and post-employment benefits | 2,637 | 2,939 |
| Total regulatory assets | 19,584 | 18,350 |
| Less: current portion | 1,301 | 2,427 |
| | 18,283 | 15,923 |
| **Regulatory liabilities:** | | |
| Deferred income tax regulatory liability | 4,333 | 4,347 |
| Total regulatory liabilities | 4,333 | 4,347 |
| Less: current portion | 120 | 109 |
| | 4,213 | 4,238 |

### Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. Management considers it probable that such expenditures will be recovered in the future through the rate-setting process, and as such, the Company has recorded an equivalent amount as a regulatory asset. In 2014, this regulatory asset increased by $180 thousand (2013 – $2,872 thousand) to reflect related changes in the Company's environmental liabilities. 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 Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2014 operation, maintenance and administration expenses would have been higher by $180 thousand (2013 – $2,872 thousand). In addition, 2014 amortization expense would have been lower by $1,598 thousand (2013 – $1,656 thousand), and 2014 financing charges would have been higher by $361 thousand (2013 – $330 thousand).

### RRPR Variance Account

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2014, the Company has recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of net RRRP amounts received. At December 31, 2013, net RRRP amounts received were also lower than amounts required to achieve breakeven net income, and as such, a regulatory asset was also recognized. In the absence of rate-regulated accounting, 2014 revenue would have been lower by $2,593 thousand (2013 – $1,198 thousand).

### Post-Retirement and Post-Employment Benefits

The Company 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 $302 thousand (2013 – $205 thousand).

### Deferred Income Tax Regulatory 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 recovery of PILs would have been lower by approximately $2 thousand (2013 – $367 thousand).

## 10. LONG-TERM DEBT

Long-term debt totalling $33,000 thousand is payable to Hydro One and consists of a $23,000 thousand note maturing in 2036 and a $10,000 thousand note maturing in 2044.

The $23,000 thousand note was issued on May 19, 2005, with an interest rate of 5.38% per annum and a maturity date of May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999 in consideration of the purchase price of Hydro One Remote Communities' net assets. On issuance of this note, $115 thousand of transaction costs and a $31 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

The $10,000 thousand note was issued on June 6, 2014, with an interest rate of 4.19% per annum and a maturity date of June 6, 2044. On issuance of this note, $50 thousand of transaction costs and a $10 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

## 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.

Hydro One Remote Communities 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 Remote Communities 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 Company's 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 Hierarchy**

The fair value hierarchy of financial assets and liabilities at December 31, 2014 and 2013 are as follows:

| *December 31, 2014 (thousands of Canadian dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 6,806 | 6,806 | 6,806 | – | – |
| Long-term debt | 33,000 | 39,226 | – | 39,226 | – |
| | 39,806 | 46,032 | 6,806 | 39,226 | – |

| *December 31, 2013 (thousands of Canadian dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 18,031 | 18,031 | 18,031 | – | – |
| Long-term debt | 23,000 | 25,450 | – | 25,450 | – |
| | 41,031 | 43,481 | 18,031 | 25,450 | – |

The fair value 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 foreign exchange risk is currently not significant, although Hydro One could in the future decide to issue and allocate foreign currency-denominated debt to the Company, along with an allocation of the resulting foreign exchange gains and losses. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%.

***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 Remote Communities 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 Company's total provision for bad debts was $304 thousand (2013 – $296 thousand). 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 36% of the Company's current accounts receivable were aged more than 60 days (2013 – 47%). Sufficient allowances have been recorded to reflect the risk of potential credit losses.

***Liquidity Risk***

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities 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 $9,812 thousand (2013 – $5,657 thousand) are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2014, Hydro One Remote Communities had long-term debt in the principal amount of $33,000 thousand (2013 – $23,000 thousand). No long-term debt matures during the next year. Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $1,656 thousand (2013 – $1,237 thousand). Principal repayments and interest payments are summarized by the number of years to maturity in the following table.

| **Years to Maturity** | **Principal Repayments on Long-term Debt** *(thousands of Canadian dollars)* | **Interest Payments** *(thousands of Canadian dollars)* | **Weighted Average Interest Rate** *(%)* |
|---|---|---|---|
| 1 year | – | 1,656 | 5.019 |
| 2 years | – | 1,656 | 5.019 |
| 3 years | – | 1,656 | 5.019 |
| 4 years | – | 1,656 | 5.019 |
| 5 years | – | 1,656 | 5.019 |
| | – | 8,280 | 5.019 |
| 6 – 10 years | – | 8,280 | 5.019 |
| Over 10 years | 33,000 | 22,405 | 5.019 |
| | 33,000 | 38,965 | 5.019 |

## 12. 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. 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 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.

Company and employees' 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, Hydro One Remote Communities charged $941 thousand (2013 – $775 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $272 thousand (2013 – $250 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2014 were $91 thousand (2013 – $264 thousand). In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $302 thousand (2013 – $205 thousand) was recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Accrued liabilities | 346 | 300 |
| Post-retirement and post-employment benefit liability | 12,862 | 12,088 |
| | 13,208 | 12,388 |

## 13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2014 and 2013:

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Environmental liabilities, January 1 | 13,426 | 11,880 |
| Interest accretion | 361 | 330 |
| Expenditures | (1,598) | (1,656) |
| Revaluation adjustment | 180 | 2,872 |
| Environmental liabilities, December 31 | 12,369 | 13,426 |
| Less: current portion | 1,301 | 2,427 |
| | 11,068 | 10,999 |

The following table illustrates 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 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Undiscounted environmental liabilities, December 31 | 12,881 | 14,014 |
| Less: discounting accumulated liabilities to present value | 512 | 588 |
| Discounted environmental liabilities, December 31 | 12,369 | 13,426 |

At December 31, 2014, the estimated future environmental expenditures were as follows:

| *(thousands of Canadian dollars)* | |
|---|---|
| 2015 | 1,301 |
| 2016 | 2,619 |
| 2017 | 2,717 |
| 2018 | 1,851 |
| 2019 | 1,657 |
| Thereafter | 2,736 |
| | 12,881 |

The Company records a liability for the estimated future expenditures for the contaminated LAR 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 3.6% to 4.9%, 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.

The Company’s best estimate of the total estimated future expenditures to complete its LAR program is $12,881 thousand. These expenditures are expected to be incurred over the period from 2015 to 2020. 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 $180 thousand (2013 – $2,872 thousand).

## 14. SHARE CAPITAL

### Common Shares

The Company has 2 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

### Dividends

The Company has no retained earnings and does not pay dividends under its breakeven business model.

## 15. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities 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 Hydro One Remote Communities because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One Remote Communities are described below.

Hydro One Remote Communities receives amounts for RRRP from the IESO. RRRP amounts received for the year ended December 31, 2014 were $32,259 thousand (2013 – $33,046 thousand). Consistent with its breakeven business model, the Company recognized $34,852 thousand as RRRP revenue in 2014 (2013 – $34,245 thousand). This 2014 revenue exceeded amounts received by $2,593 thousand (2013 – $1,199 thousand) and the RRPR variance account balance was adjusted by this amount.

PILs are paid to or received from the OEFC.

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

| *December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Accounts receivable | 106 | 97 |
| Income tax receivable | 2,683 | 2,697 |

Transactions with 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.

### Hydro One and Subsidiaries

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its other 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 corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2014 revenues include $109 thousand (2013 – $195 thousand) related to the provision of services to Hydro One and its other subsidiaries. 2014 operation, maintenance and administration costs include $2,958 thousand (2013 – $3,475 thousand) related to the purchase of services from Hydro One and its other subsidiaries.

The Company's long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One and its other subsidiaries. Financing charges include interest expense on the long-term debt in the amount of $1,477 thousand (2013 – $1,237 thousand), and interest expense on the inter-company demand facility in the amount of $187 thousand (2013 – $216 thousand). At December 31, 2014, the Company had accrued interest payable to Hydro One totaling $172 thousand (2013 – $142 thousand).

## 16. STATEMENTS OF CASH FLOWS

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

| *Year ended December 31 (thousands of Canadian dollars)* | **2014** | **2013** |
|---|---|---|
| Accounts receivable | 541 | (802) |
| Materials and supplies | (356) | 443 |
| Income taxes receivable | 14 | (1,108) |
| Long-term accounts receivable | (576) | (256) |
| Accounts payable | 173 | (284) |
| Accrued liabilities | 5,105 | (1,526) |
| Accrued interest | 30 | – |
| Post-retirement and post-employment benefit liability | 1,076 | 760 |
| | 6,007 | (2,773) |
| **Supplementary information:** | | |
| Net interest paid | 1,447 | 1,453 |

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any PILs paid are fully recovered.

## 17. CONTINGENCIES

### Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

### Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One 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, Hydro One paid approximately $1 million (2013 – $2 million) in respect of these consents. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One 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 Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

## 18. COMMITMENTS

### Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years.

During the year ended December 31, 2014, the Company made lease payments totalling $120 thousand (2013 – $1 million). At December 31, 2014, the future minimum lease payments under non-cancellable operating leases were as follows: 2015 – $120 thousand; 2016 – $120 thousand; 2017 – $120 thousand; 2018 – $150 thousand; 2019 – $150 thousand; and thereafter – $450 thousand.

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**SCHEDULE 100**

Form identifier 100

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2014-12-31 |

## Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 10,650,000 | 11,963,000 |
| | Total tangible capital assets | 2008 | + | 67,506,000 | 64,028,000 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 24,588,000 | 23,256,000 |
| | Total intangible capital assets | 2178 | + | | |
| | Total accumulated amortization of intangible capital assets | 2179 | – | | |
| | Total long-term assets | 2589 | + | 23,929,000 | 20,960,000 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 77,497,000 | 73,695,000 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 16,910,000 | 23,939,000 |
| | Total long-term liabilities | 3450 | + | 61,143,000 | 50,325,000 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 78,053,000 | 74,264,000 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | -556,000 | -569,000 |
| | **Total liabilities and shareholder equity** | 3640 | = | 77,497,000 | 73,695,000 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | | |

* Generic item

Canada Revenue Agency | Agence du revenu du Canada

**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2014-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | Ontario Hydro Remote Communities Service Company Inc. |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

### Income statement information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | Total sales of goods and services | 8089 | + | 52,130,000 | 50,035,000 |
| | Cost of sales | 8518 | – | 25,869,000 | 25,568,000 |
| | **Gross profit/loss** | 8519 | = | 26,261,000 | 24,467,000 |
| | Cost of sales | 8518 | + | 25,869,000 | 25,568,000 |
| | Total operating expenses | 9367 | + | 26,251,000 | 25,558,000 |
| | **Total expenses** (mandatory field) | 9368 | = | 52,120,000 | 51,126,000 |
| | Total revenue (mandatory field) | 8299 | + | 52,130,000 | 50,035,000 |
| | Total expenses (mandatory field) | 9368 | – | 52,120,000 | 51,126,000 |
| | **Net non-farming income** | 9369 | = | 10,000 | -1,091,000 |

### Farming income statement information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | 10,000 | -1,091,000 |
| | **Total other comprehensive income** | 9998 | = | 13,000 | 13,000 |

### Extraordinary items and income (linked to Schedule 140)

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | 10,000 | -1,091,000 |
| | Future (deferred) income tax provision | 9995 | – | | |
| | Total – Other comprehensive income | 9998 | + | 13,000 | 13,000 |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 13,000 | 13,000 |

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**Schedule 141**

# Notes checklist

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2014-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

**Note**
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: . . . . . **198**

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

## Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [X]

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: . . . . . **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 [X]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income Increase (decrease) | | In OCI Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

## Detailed information (continued)

- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

## Part 1 – Investments, expenditures, and percentages

| **Investments** | **Specified percentage** |
|---|---|
| Qualified property acquired primarily for use in Atlantic Canada . . . | 10 % |
| Qualified resource property acquired primarily for use in Atlantic Canada and acquired: | |
| – after March 28, 2012, and before 2014 . . . | 10 % |
| – after 2013 and before 2016 . . . | 5 % |
| – after 2015* . . . | 0 % |
| **Expenditures** | |
| If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10) . . . | 35 % |
| **Note:** If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**. | |
| If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada: | |
| – before 2014** . . . | 20 % |
| – after 2013** . . . | 15 % |
| If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012 . . . | 10 % |
| If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***: | |
| – after March 28, 2012, and before 2013 . . . | 10 % |
| – in 2013 . . . | 5 % |
| – after 2013*** . . . | 0 % |
| If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****: | |
| – after March 28, 2012, and before 2014**** . . . | 10 % |
| – in 2014 . . . | 7 % |
| – in 2015 . . . | 4 % |
| – after 2015**** . . . | 0 % |
| If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment . . . | 10 % |
| If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children . . . | 25 % |

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more information. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

## Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **101** 1 Yes X 2 No

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

**Note:** A CCPC calculating a refundable ITC is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or
c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

## Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **102** 1 Yes 2 No X

Contributions to agricultural organizations for SR&ED* . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **103**

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see Guide RC4088, *General Index of Financial Information (GIFI)*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661. Include all of the contributions made before 2013 and 80% of the contributions made after 2012.

## Qualified Property and Qualified Resource Property

## Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

| CCA* class number **105** | Description of investment **110** | Date available for use **115** | Location used (province or territory) **120** | Amount of investment **125** |
|---|---|---|---|---|
| | | | | |
| | | | **Total of investments for qualified property and qualified resource property** | A |

* CCA: capital cost allowance

## Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | B |
| **Deduct:** | | | | |
| Credit deemed as a remittance of co-op corporations | 210 | | | |
| Credit expired | 215 | | | |
| Subtotal (line 210 **plus** line 215) | | | | C |
| ITC at the beginning of the tax year (amount B **minus** amount C) | | 220 | | |
| **Add:** | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 230 | | | |
| ITC from repayment of assistance | 235 | | | |
| Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part of amount A from Part 4) ______ x 10 % = | 240 | | | |
| Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part of amount A from Part 4) ______ x 5 % = | 242 | | | |
| Credit allocated from a partnership | 250 | | | |
| Subtotal (total of lines 230 to 250) | | | | D |
| Total credit available (line 220 **plus** amount D) | | | | E |
| **Deduct:** | | | | |
| Credit deducted from Part I tax (enter at amount D in Part 30) | 260 | | | |
| Credit carried back to the previous year(s) (amount H from Part 6) | | a | | |
| Credit transferred to offset Part VII tax liability | 280 | | | |
| Subtotal (total of line 260, amount a, and line 280) | | | | F |
| Credit balance before refund (amount E **minus** amount F) | | | | G |
| **Deduct:** | | | | |
| Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) | | 310 | | |
| **ITC closing balance of investments from qualified property and qualified resource property** (amount G **minus** line 310) | | 320 | | |

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

## Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 901 | |
| 2nd previous tax year | | | | Credit to be applied | 902 | |
| 3rd previous tax year | | | | Credit to be applied | 903 | |
| | | | | **Total** (enter at amount a in Part 5) | | H |

## Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

| | | |
|---|---|---|
| Current-year ITCs (total of lines 240, 242, and 250 from Part 5) | | I |
| Credit balance before refund (amount G from Part 5) | | J |
| **Refund** ( 40 % of amount I or J, whichever is less) | | K |

Enter amount K or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

# SR&ED

## Part 8 – Qualified SR&ED expenditures

**Current expenditures**

| | | | | |
|---|---|---|---|---|
| Current expenditures (from line 557 on Form T661) | | | | |
| Contributions to agricultural organizations for SR&ED | | | | |
| **Deduct:** Government assistance, non-government assistance, or contract payment | | | | |
| Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)* | | + ▶ | | |
| Current expenditures (line 557 on Form T661 **plus** line 103 from Part 3)* | | | 350 | |
| Capital expenditures incurred **before** 2014 (from line 558 on Form T661)** | | | 360 | |
| Repayments made in the year (from line 560 on Form T661) | | | 370 | |
| **Qualified SR&ED expenditures** (total of lines 350 to 370) | | | 380 | |

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures.

## Part 9 – Components of the SR&ED expenditure limit calculation

**Part 9 only applies if the corporation is a CCPC.**

**Note:** A CCPC that calculates an SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and

one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [ ] 2 No [X]

Complete lines 390 and 398 if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) 390 ______

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million 398 ______

* If either of the tax years referred to at line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

## Part 10 – SR&ED expenditure limit for a CCPC

| | | | | |
|---|---|---|---|---|
| **For a stand-alone corporation:** | | | $ 8,000,000 | |
| **Deduct:** | | | | |
| Taxable income for the previous tax year (line 390 from Part 9) or $500,000, whichever is more | 500,000 | x 10 = | 5,000,000 | A |
| Excess ($8,000,000 **minus** amount A; if negative, enter "0") | | | 3,000,000 | B |
| $ 40,000,000 **minus** line 398 from Part 9 | 40,000,000 | a | | |
| Amount a **divided** by $ 40,000,000 | | | 1 | C |
| **Expenditure limit for the stand-alone corporation** (amount B **multiplied** by amount C) | | | 3,000,000 | D* |
| **For an associated corporation:** | | | | |
| If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 | | | | E* |

**Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:**

Amount D or E 3,000,000 x Number of days in the tax year / 365 = 304 / 365 = 2,498,630 F

**Your SR&ED expenditure limit for the year** (enter the amount from line D, E, or F, whichever applies) 410 2,498,630

* Amount D or E cannot be more than $3,000,000.

## Part 11 – Investment tax credits on SR&ED expenditures

| | | | | | |
|---|---|---|---|---|---|
| Current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10), whichever is less* | 420 | | x 35 % = | | G |
| Line 350 **minus** line 410 (if negative, enter "0")** | 430 | | x 15 % = | | H |
| Line 410 **minus** line 350 (if negative, enter "0") | | 2,498,630 | b | | |
| Capital expenditures (line 360 from Part 8) or amount b above, whichever is less* | 440 | | x 35 % = | | I |
| Line 360 **minus** amount b above (if negative, enter "0")** | 450 | | x 15 % = | | J |
| **Repayments** (amount from line 370 in Part 8) | | | | | |

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.**

| | | | | |
|---|---|---|---|---|
| 460 | | x 35 % = | | c |
| 480 | | x 15 % = | | d |
| Subtotal (amount c **plus** amount d) | | | | K |

**Current-year SR&ED ITC** (total of amounts G to K; enter on line 540 in Part 12) ........ L

* For corporations that are not CCPCs, enter "0" for amounts G and I.

** For tax years that end after 2013, the general SR&ED rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

## Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | M |
| **Deduct:** | | | | |
| Credit deemed as a remittance of co-op corporations | 510 | | | |
| Credit expired | 515 | | | |
| Subtotal (line 510 **plus** line 515) | | | | N |
| ITC at the beginning of the tax year (amount M **minus** amount N) | | | 520 | |
| **Add:** | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 530 | | | |
| Total current-year credit (from amount L in Part 11) | 540 | | | |
| Credit allocated from a partnership | 550 | | | |
| Subtotal (total of lines 530 to 550) | | | | O |
| Total credit available (line 520 **plus** amount O) | | | | P |
| **Deduct:** | | | | |
| Credit deducted from Part I tax (enter at amount E in Part 30) | 560 | | | |
| Credit carried back to the previous year(s) (amount S from Part 13) | | | e | |
| Credit transferred to offset Part VII tax liability | 580 | | | |
| Subtotal (total of line 560, amount e, and line 580) | | | | Q |
| Credit balance before refund (amount P **minus** amount Q) | | | | R |
| **Deduct:** | | | | |
| Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) | | | 610 | |
| **ITC closing balance on SR&ED** (amount R **minus** line 610) | | | 620 | |

## Part 13 – Request for carryback of credit from SR&ED expenditures

| | Year | Month | Day | | | | |
|---|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 911 | | |
| 2nd previous tax year | | | | Credit to be applied | 912 | | |
| 3rd previous tax year | | | | Credit to be applied | 913 | | |
| | | | | **Total** (enter at amount e in Part 12) | | | S |

## Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . 650 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 from Part 12 **minus** amount K from Part 11) . . . ________ f

Refundable credits (amount f above or amount R from Part 12, whichever is less)* . . . ________ T

**Deduct:**

Amount T or amount G from Part 11, whichever is less . . . ________ U

Net amount (amount T **minus** amount U; if negative, enter "0") . . . ________ V

Amount V **multiplied** by 40 % . . . ________ W

**Add:**

Amount U . . . ________ X

**Refund of ITC** (amount W **plus** amount X – enter this, or a lesser amount, on line 610 in Part 12) . . . ________ Y

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y.

## Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined at line 101 in Part 2.

Credit balance before refund (amount R from Part 12) . . . ________ Z

**Deduct:**

Amount Z or amount G from Part 11, whichever is less . . . ________ AA

Net amount (amount Z **minus** amount AA; if negative, enter "0") . . . ________ BB

Amount BB or amount I from Part 11, whichever is less . . . ________ CC

Amount CC **multiplied** by 40 % . . . ________ DD

**Add :**

Amount AA . . . ________ EE

**Refund of ITC** (amount DD **plus** amount EE) . . . ________ FF

Enter FF, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

# Recapture – SR&ED

## Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

**Note:**

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

### Calculation 1 – If you meet all of the above conditions

| Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700** | Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710** | Amount from column 700 or 710, whichever is less |
|---|---|---|
| | | |

**Subtotal** (enter this amount at amount C in Part 17) A

### Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B in Part 16 on page 9.

| A<br>Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720** | B<br>Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730** | C<br>Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740** |
|---|---|---|
| | | |

### Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B below.

| D<br>Amount determined by the formula (A x B) – C | E<br>ITC earned by the transferee for the qualified expenditures that were transferred **750** | F<br>Amount from column D or E, whichever is less |
|---|---|---|
| | | |

**Subtotal** (enter this amount at amount D in Part 17) B

**Calculation 3**

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760 below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported at amount E in Part 17) **760** ______

## Part 17 – Total recapture of SR&ED investment tax credit

| | | |
|---|---|---|
| Recaptured ITC for calculation 1 from amount A in Part 16 | | C |
| Recaptured ITC for calculation 2 from amount B in Part 16 | | D |
| Recaptured ITC for calculation 3 from line 760 in Part 16 | | E |
| **Total recapture of SR&ED investment tax credit** – total of amounts C to E | | F |

Enter amount F at amount A in Part 29.

# Pre-Production Mining

## Part 18 – Pre-production mining expenditures

### Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

| List of minerals 800 | Project name 805 |
|---|---|
| | |

| Mineral title 806 | Mining division 807 |
|---|---|
| | |

### Pre-production mining expenditures*

**Exploration:**

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting . . . . . 810

Geological, geophysical, or geochemical surveys . . . . . 811

Drilling by rotary, diamond, percussion, or other methods . . . . . 812

Trenching, digging test pits, and preliminary sampling . . . . . 813

**Development:**

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping . . . . . 820

Sinking a mine shaft, constructing an adit, or other underground entry . . . . . 821

Other pre-production mining expenditures incurred in the tax year:

| Description 825 | Amount 826 |
|---|---|
| | |

Add amounts in column 826 A

Total pre-production mining expenditures (total of lines 810 to 821 and amount A) . . . . . 830

**Deduct:**

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above . . . . . 832

Excess (line 830 **minus** line 832) (if negative, enter "0") . . . . . B

**Add:**

Repayments of government and non-government assistance . . . . . 835

**Pre-production mining expenditures** (amount B **plus** line 835) . . . . . C

* A pre-production mining expenditure is defined under subsection 127(9).

## Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | D |
| **Deduct:** | | | | |
| Credit deemed as a remittance of co-op corporations | 841 | | | |
| Credit expired | 845 | | | |
| Subtotal (line 841 **plus** line 845) | | | | E |
| ITC at the beginning of the tax year (amount D **minus** amount E) | 850 | | | |
| **Add:** | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 860 | | | |
| Pre-production mining expenditures* incurred before January 1, 2013 (applicable part of amount C from Part 18) | 870 | x 10 % = | | a |
| Pre-production mining exploration expenditures incurred in 2013 (applicable part of amount C from Part 18) | 872 | x 5 % = | | b |
| Pre-production mining development expenditures incurred in 2014 (applicable part of amount C from Part 18) | 874 | x 7 % = | | c |
| Pre-production mining development expenditures incurred in 2015 (applicable part of amount C from Part 18) | 876 | x 4 % = | | d |
| Current year credit (total of amounts a to d) | 880 | | | F |
| Total credit available (total of lines 850, 860, and amount F) | | | | G |
| **Deduct:** | | | | |
| Credit deducted from Part I tax (enter at amount F in Part 30) | 885 | | | |
| Credit carried back to the previous year(s) (amount I from Part 20) | | | | e |
| Subtotal (line 885 **plus** amount e) | | | | H |
| **ITC closing balance from pre-production mining expenditures** (amount G **minus** amount H) | 890 | | | |

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

## Part 20 – Request for carryback of credit from pre-production mining expenditures

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 921 | |
| 2nd previous tax year | | | | Credit to be applied | 922 | |
| 3rd previous tax year | | | | Credit to be applied | 923 | |
| | | | | **Total** (enter at amount e in Part 19) | | I |

# Apprenticeship Job Creation

## Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) ....... 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

| A<br>Contract number<br>(SIN or name of apprentice)<br>601 | B<br>Name of eligible trade<br>602 | C<br>Eligible salary and wages*<br>603 | D<br>Column C x 10 %<br>604 | E<br>Lesser of column D or $ 2,000<br>605 |
|---|---|---|---|---|
| | | | | |

Total current-year credit (enter at line 640 in Part 22) ______ A

* Net of any other government or non-government assistance received or to be received.

## Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

| | | | |
|---|---|---|---|
| ITC at the end of the previous tax year | | 2,849 | B |
| **Deduct:** | | | |
| Credit deemed as a remittance of co-op corporations .... 612 | | | |
| Credit expired after 20 tax years .... 615 | | | |
| Subtotal (line 612 **plus** line 615) | | | C |
| ITC at the beginning of the tax year (amount B **minus** amount C) .... 625 | | 2,849 | |
| **Add:** | | | |
| Credit transferred on amalgamation or wind-up of subsidiary .... 630 | | | |
| ITC from repayment of assistance .... 635 | | | |
| Total current-year credit (amount A from Part 21) .... 640 | | | |
| Credit allocated from a partnership .... 655 | | | |
| Subtotal (total of lines 630 to 655) | | | D |
| Total credit available (line 625 **plus** amount D) | | 2,849 | E |
| **Deduct:** | | | |
| Credit deducted from Part I tax (enter at amount G in Part 30) .... 660 | 2,849 | | |
| Credit carried back to the previous year(s) (amount G from Part 23) | | | a |
| Subtotal (line 660 **plus** amount a) | 2,849 | 2,849 | F |
| **ITC closing balance from apprenticeship job creation expenditures** (amount E **minus** amount F) .... 690 | | | |

## Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

| | Year | Month | Day | | |
|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied 931 | |
| 2nd previous tax year | | | | Credit to be applied 932 | |
| 3rd previous tax year | | | | Credit to be applied 933 | |

**Total** (enter at amount a in Part 22) ______ G

# Child Care Spaces

## Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

### Cost of depreciable property from the current tax year

| | CCA* class number 665 | Description of investment 675 | Date available for use 685 | Amount of investment 695 |
|---|---|---|---|---|
| 1. | | | | |

Total cost of depreciable property from the current tax year **715** ______

**Add:**

Specified child care start-up expenditures from the current tax year . . . . . **705** ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ______ A

**Deduct:**

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line A . . . . . **725** ______

Excess (amount A **minus** line 725) (if negative, enter "0") . . . . . ______ B

**Add:**

Repayments by the corporation of government and non-government assistance . . . . . **735** ______

**Total eligible expenditures for child care spaces** (amount B **plus** line 735) . . . . . **745** ______

* CCA: capital cost allowance

## Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745) . . . . . ______ x 25 % = ______ C

Number of child care spaces . . . . . **755** ______ x $ 10,000 = ______ D

**ITC from child care spaces expenditures** (amount C or D, whichever is less) . . . . . ______ E

## Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | F |
| **Deduct:** | | | | |
| Credit deemed as a remittance of co-op corporations | 765 | | | |
| Credit expired after 20 tax years | 770 | | | |
| Subtotal (line 765 **plus** line 770) | | | | G |
| ITC at the beginning of the tax year (amount F **minus** amount G) | | | 775 | |
| **Add:** | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 777 | | | |
| Total current-year credit (amount E from Part 25) | 780 | | | |
| Credit allocated from a partnership | 782 | | | |
| Subtotal (total of lines 777 to 782) | | | | H |
| Total credit available (line 775 **plus** amount H) | | | | I |
| **Deduct:** | | | | |
| Credit deducted from Part I tax (enter at amount H in Part 30) | 785 | | | |
| Credit carried back to the previous year(s) (amount K from Part 27) | | | a | |
| Subtotal (line 785 **plus** amount a) | | | | J |
| **ITC closing balance from child care spaces expenditures** (amount I **minus** amount J) | | | 790 | |

## Part 27 – Request for carryback of credit from child care space expenditures

| | Year Month Day | | | |
|---|---|---|---|---|
| 1st previous tax year | 2014-12-31 | Credit to be applied | 941 | |
| 2nd previous tax year | 2013-12-31 | Credit to be applied | 942 | |
| 3rd previous tax year | 2012-12-31 | Credit to be applied | 943 | |
| | | **Total** (enter at amount a in Part 26) | | K |

## Recapture – Child Care Spaces

### Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

the new child care space is no longer available; or

property that was an eligible expenditure for the child care space is:

– disposed of or leased to a lessee; or
– converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . . . . . . . . . . . . . . . . . . . . . . **792** ______

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . . . . . . . . . . . . . . . . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ A

**Corporate partnerships**

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

**Corporate partner's share of the excess of ITC** **799** ______

**Total recapture of child care spaces investment tax credit** (total of line 792, amount A, and line 799) . . . . . . . . . . . . . . . ______ B
Enter amount B at amount B in Part 29.

## Summary of Investment Tax Credits

### Part 29 – Total recapture of investment tax credit

| | | |
|---|---|---|
| Recaptured SR&ED ITC (from amount F in Part 17) | | A |
| Recaptured child care spaces ITC (from amount B in Part 28) | | B |
| **Total recapture of investment tax credit** (amount A **plus** amount B) | | C |

Enter amount C on line 602 of the T2 return.

### Part 30 – Total ITC deducted from Part I tax

| | | |
|---|---|---|
| ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) | | D |
| ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) | | E |
| ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) | | F |
| ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) | 2,849 | G |
| ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) | | H |
| **Total ITC deducted from Part I tax** (total of amounts D to H) | 2,849 | I |

Enter amount I at line 652 of the T2 return.

*Privacy Act*, Personal Information Bank number CRA PPU 047

# Summary of Investment Tax Credit Carryovers

## Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

**Current year**

| | Addition current year (A) | Applied current year (B) | Claimed as a refund (C) | Carried back (D) | ITC end of year (A-B-C-D) |
|---|---|---|---|---|---|
| | | | | | |

**Prior years**

| Taxation year | ITC beginning of year (E) | Adjustments (F) | Applied current year (G) | ITC end of year (E-F-G) |
|---|---|---|---|---|
| 2014-12-31 | 2,000 | | 2,000 | |
| 2013-12-31 | | | | |
| 2012-12-31 | 849 | | 849 | |
| 2011-12-31 | | | | |
| 2010-12-31 | | | | |
| 2009-12-31 | | | | |
| 2008-12-31 | | | | |
| 2007-12-31 | | | | |
| 2006-12-31 | | | | |
| 2005-12-31 | | | | * |
| 2004-12-31 | | | | |
| 2003-12-31 | | | | |
| 2002-12-31 | | | | |
| 2001-12-31 | | | | |
| 2000-12-31 | | | | |
| 1999-12-31 | | | | |
| | | | | |
| 0000-02-29 | | | | |
| 1997-03-31 | | | | |
| 1996-03-31 | | | | * |
| **Total** | 2,849 | | 2,849 | |

B+C+D+G **Total ITC utilized** 2,849

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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**SCHEDULE 50**

# SHAREHOLDER INFORMATION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

| | Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100 | Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") 200 | Social insurance number 300 | Trust number 350 | Percentage common shares 400 | Percentage preferred shares 500 |
|---|---|---|---|---|---|---|
| 1 | Hydro One Inc. | 86999 4731 RC0001 | | | 100.000 | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |



Canada

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**Schedule 53**

# General Rate Income Pool (GRIP) Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

On: 2015-10-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

## Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

**2006 addition**

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 . . . . . 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   **If the answer to question 3 is yes, complete Part "GRIP addition for 2006".**

**Change in the type of corporation**

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   **If the answer to question 5 is yes, complete Part 4.**

**Amalgamation (first year of filing after amalgamation)**

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   **If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.**
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   **If the answer to question 7 is yes, complete Part 4.**
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   **If the answer to question 8 is yes, complete Part 3.**

**Winding-up**

9. Has the corporation wound-up a subsidiary in the preceding taxation year? . . . . . ☐ Yes ☒ No
   **If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.**
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    **If the answer to question 10 is yes, complete Part 4.**
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    **If the answer to question 11 is yes, complete Part 3.**

## Part 1 – General rate income pool (GRIP)

| | | | | |
|---|---|---|---|---|
| GRIP at the end of the previous tax year | | | 100 | -280,626 A |
| Taxable income for the year (DICs enter "0") * | 110 | 1,188,984 B | | |
| Income for the credit union deduction * (amount E in Part 3 of Schedule 17) | 120 | | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * | 130 | | | |
| For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * | 140 | | | |
| Subtotal (**add** lines 120, 130, and 140) | | C | | |
| Income taxable at the general corporate rate (amount B **minus** amount C) (if negative enter "0") | 150 | 1,188,984 | | |
| After-tax income (line 150 **multiplied** by 0.72 (the general rate factor for the tax year)) | | | 190 | 856,068 D |
| Eligible dividends received in the tax year | 200 | | | |
| Dividends deductible under section 113 received in the tax year | 210 | | | |
| Subtotal (line 200 **plus** line 210) | | | | E |
| GRIP addition: | | | | |
| Becoming a CCPC (from amount PP in Part 4) | 220 | | | |
| Post-amalgamation (total of amounts EE in Part 3 and amounts PP in Part 4) | 230 | | | |
| Post-wind-up (total of amounts EE in Part 3 and amounts PP in Part 4) | 240 | | | |
| Subtotal (**add** lines 220, 230, and 240) | 290 | | | F |
| Subtotal (**add** amounts A, D, E, and F) | | | | 575,442 G |
| Eligible dividends paid in the previous tax year | 300 | | | |
| Excessive eligible dividend designations made in the previous tax year | 310 | | | |
| (If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.) | | | | |
| Subtotal (line 300 **minus** line 310) | | | | H |
| GRIP before adjustment for specified future tax consequences (amount G **minus** amount H) (amount can be negative) | | | 490 | 575,442 |
| Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2) | | | 560 | |
| **GRIP at the end of the tax year** (line 490 **minus** line 560) Enter this amount on line 160 of Schedule 55. | | | 590 | 575,442 |

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

**First previous tax year** 2014-12-31

| | | | |
|---|---|---|---|
| Taxable income before specified future tax consequences from the current tax year | | J1 | |
| Enter the following amounts before specified future tax consequences from the current tax year: | | | |
| Income for the credit union deduction (amount E in Part 3 of Schedule 17) | K1 | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less | L1 | | |
| Aggregate investment income (line 440 of the T2 return) | M1 | | |
| Subtotal (**add** amounts K1, L1, and M1) | ▶ | N1 | |
| Subtotal (amount J1 **minus** amount N1) (if negative, enter "0") | | ▶ | O1 |

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S1

Subtotal (**add** amounts Q1, R1, and S1) ______ ► ______ T1

Subtotal (amount P1 **minus** amount T1) (if negative, enter "0") ______ ► ______ U1

Subtotal (amount O1 **minus** amount U1) (if negative, enter "0") ______ V1

**GRIP adjustment for specified future tax consequences to the first previous tax year**
(amount V1 **multiplied** by 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** ______

**Second previous tax year** 2013-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ M2

Subtotal (**add** amounts K2, L2, and M2) ______ ► ______ N2

Subtotal (amount J2 **minus** amount N2) (if negative, enter "0") ______ ► ______ O2

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S2

Subtotal (**add** amounts Q2, R2, and S2) ______ ► ______ T2

Subtotal (amount P2 **minus** amount T2) (if negative, enter "0") ______ ► ______ U2

Subtotal (amount O2 **minus** amount U2) (if negative, enter "0") ______ V2

**GRIP adjustment for specified future tax consequences to the second previous tax year**
(amount V2 **multiplied** by 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **520** ______

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

**Third previous tax year** 2012-12-31

Taxable income before specified future tax consequences from the current tax year .......... J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less .... L3

Aggregate investment income (line 440 of the T2 return) ......... M3

Subtotal (**add** amounts K3, L3, and M3) ▶ N3

Subtotal (amount J3 **minus** amount N3) (if negative, enter "0") ▶ O3

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences ........ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less .... R3

Aggregate investment income (line 440 of the T2 return) ......... S3

Subtotal (**add** amounts Q3, R3, and S3) ▶ T3

Subtotal (amount P3 **minus** amount T3) (if negative, enter "0") ▶ U3

Subtotal (amount O3 **minus** amount U3) (if negative, enter "0") V3

**GRIP adjustment for specified future tax consequences to the third previous tax year**
(amount V3 **multiplied by** 0.72 ) .......... **540**

**Total GRIP adjustment for specified future tax consequences to previous tax years:**
(**add** lines 500, 520, and 540) (if negative, enter "0") .......... W

Enter amount W on line 560 in part 1.

## Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

**nb. 1** Post amalgamation ... ☐ Post wind-up ...... ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year .......... AA

Eligible dividends paid by the corporation in its last tax year .......... BB

Excessive eligible dividend designations made by the corporation in its last tax year .......... CC

Subtotal (amount BB **minus** amount CC) ▶ DD

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)**
(amount AA **minus** amount DD) .......... EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE amounts. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

**nb. 1** Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . ______ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . ______ GG

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ a
Net capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ b
Farm losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ c
Restricted farm losses . . . . . . . . . . . . . . . . . . . . . . . . ______ d
Limited partnership losses . . . . . . . . . . . . . . . . . . . . . ______ e

Subtotal (**add** amounts a to e) ______ ► ______ 1

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ f
Net capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ g
Farm losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ h
Restricted farm losses . . . . . . . . . . . . . . . . . . . . . . . . ______ i
Limited partnership losses . . . . . . . . . . . . . . . . . . . . . ______ j

Subtotal (**add** amounts f to j) ______ ► ______ 2

Unused and unexpired losses at the end of the corporation's previous/last tax year (amount 1 **minus** amount 2) ______ ► ______ HH

Subtotal (**add** amounts FF, GG, and HH) ______ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . ______ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . ______ KK

All the corporation's reserves deducted in its previous/last tax year . . . . . . . . . . . . . . . . . . ______ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ NN

Subtotal (**add** amounts JJ to NN) ______ ► ______ OO

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC** (amount II **minus** amount OO) (if negative, enter "0") . . . . . . . . . . . . . . . . . ______ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP amounts. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

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**Schedule 88**

# Internet Business Activities

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

- File this schedule if your corporation earns income from one or more webpages or websites.
- You may earn income from your webpages or websites if:
  - you sell goods and/or services on your own pages or websites. You may have a shopping cart and process payment transactions yourself or through a third-party service;
  - your site doesn't support transactions but your customers call, complete, and submit a form, or email you to make a purchase, order, booking, and others;
  - you sell goods and/or services on auction, marketplace, or similar websites operated by others; or
  - you earn income from advertising, income programs, or traffic your site generates. For example:
    - static advertisements you place on your site for other businesses
    - affiliate programs
    - advertising programs such as Google AdSense or Microsoft adCentre
    - other types of traffic programs.
- Also file this schedule if you don't have a website but you have created a profile or other page describing your business on blogs, auction, market place, or any other portal or directory websites from which you earn income.
- File this schedule with your *T2 – Corporation Income Tax Return*.

How many Internet webpages or websites does your corporation earn income from? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1

Provide the Internet webpage or website addresses (also known as URL addresses)*:

http:// http://www.hydroone.com/OURCOMMITMENT/REMOTECOMMUNITIES/Pages/home.aspx

http://

http://

http://

http://

What is the percentage of the corporation's gross revenue generated from the Internet in comparison to the corporation's total gross revenue? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 0.01 %

* If you have more than five websites, enter the addresses of those that generate the most Internet income. If you don't have a website but you have created a profile or other page describing your business on blogs, auction, market place, or any other portal or directory websites, enter the addresses of the pages if they generate income.



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**Schedule 500**

# Ontario Corporation Tax Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

## Part 1 – Ontario basic rate of tax for the year

**Ontario basic rate of tax for the year** . . . . . . . . . . 11.5 % A

## Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . . . . . . 1,188,984 B

**Ontario basic income tax**: amount B **multiplied** by Ontario basic rate of tax for the year (rate A from Part 1) . . . . . . . 136,733 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

## Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

| | | |
|---|---|---|
| Income from active business carried on in Canada (amount from line 400 of the T2 return) | 4,474,062 | 1 |
| Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) | | 2 |
| Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) | | 3 |

**Ontario business limit reduction:**

Amount from line 3 ______ a

**Deduct:**

Amount from line E of the T2 return ______ x Number of days in the tax year after May 1, 2014 / Number of days in the tax year = 304 / 304 = ______ b

Reduced Ontario business limit (amount a **minus** amount b) (if negative, enter "0") ______ ► ______ 4

Enter the least of amounts 1, 2, 3, and 4 ______ D

Ontario domestic factor (ODF): Ontario taxable income * / Taxable income earned in all provinces and territories ** = 1,188,984.00 / 1,188,984 = 1.00000 E

Amount D × ODF (line E) ______ c

Ontario taxable income (amount B from Part 2) 1,188,984 d

Ontario small business income (lesser of amount c and amount d) ______ F

OSBD rate for the year 7 % G

**Ontario small business deduction**: amount F **multiplied** by rate G ______ H
Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

## Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

**Ontario adjusted small business income** (lesser of amount D and amount d from Part 3) ______ I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

## Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

| | | | | |
|---|---|---|---|---|
| Amount D from Part 3 of Schedule 17 | | J | | |
| **Deduct:** | | | | |
| Ontario adjusted small business income (amount I from Part 4) | | K | | |
| Subtotal (amount J **minus** amount K) (if negative, enter "0") | | L | | |
| Amount L **multiplied** by rate G from Part 3 | | | | M |
| Ontario domestic factor (line E from Part 3) | | | 1.00000 | N |
| **Ontario credit union tax reduction** (amount M **multiplied** by ODF from line N) | | | | O |

Enter amount O on line 410 of Schedule 5.

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**Schedule 510**

# Ontario Corporate Minimum Tax

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Determination of CMT applicability

| | | |
|---|---|---|
| Total assets of the corporation at the end of the tax year * | 112 | 72,228,000 |
| Share of total assets from partnership(s) and joint venture(s) * | 114 | |
| Total assets of associated corporations (amount from line 450 on Schedule 511) | 116 | 10,000,000,000 |
| Total assets (total of lines 112 to 116) | | 10,072,228,000 |
| Total revenue of the corporation for the tax year ** | 142 | 48,008,306 |
| Share of total revenue from partnership(s) and joint venture(s) ** | 144 | |
| Total revenue of associated corporations (amount from line 550 on Schedule 511) | 146 | 5,000,000,000 |
| Total revenue (total of lines 142 to 146) | | 5,048,008,306 |

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

## Part 2 – Adjusted net income/loss for CMT purposes

| | | | | |
|---|---|---|---|---|
| Net income/loss per financial statements * | | | 210 | -4,988,000 |
| **Add** (to the extent reflected in income/loss): | | | | |
| Provision for current income taxes/cost of current income taxes | 220 | 5,158,000 | | |
| Provision for deferred income taxes (debits)/cost of future income taxes | 222 | | | |
| Equity losses from corporations | 224 | | | |
| Financial statement loss from partnerships and joint ventures | 226 | | | |
| Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act | 230 | | | |
| **Other additions** (see note below): | | | | |
| Share of adjusted net income of partnerships and joint ventures ** | 228 | | | |
| Total patronage dividends received, not already included in net income/loss | 232 | | | |
| 281 | 282 | | | |
| 283 | 284 | | | |
| Subtotal | | 5,158,000 | | 5,158,000 A |
| **Deduct** (to the extent reflected in income/loss): | | | | |
| Provision for recovery of current income taxes/benefit of current income taxes | 320 | | | |
| Provision for deferred income taxes (credits)/benefit of future income taxes | 322 | | | |
| Equity income from corporations | 324 | | | |
| Financial statement income from partnerships and joint ventures | 326 | | | |
| Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act | 330 | | | |
| Dividends not taxable under section 83 of the federal Act (from Schedule 3) | 332 | | | |
| Gain on donation of listed security or ecological gift | 340 | | | |
| Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act *** | 342 | | | |
| Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act **** | 344 | | | |
| Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act ***** | 346 | | | |
| Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act | 348 | | | |
| **Other deductions** (see note below): | | | | |
| Share of adjusted net loss of partnerships and joint ventures ** | 328 | | | |
| Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3 | 334 | | | |
| Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss | 336 | | | |
| Patronage dividends paid (from Schedule 16) not already included in net income/loss | 338 | | | |
| 381 Other comprehensive income included in income | 382 | 12,000 | | |
| 383 | 384 | | | |
| 385 | 386 | | | |
| 387 | 388 | | | |
| 389 | 390 | | | |
| Subtotal | | 12,000 | | 12,000 B |
| Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B) | | | 490 | 158,000 |

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

**Note**

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

## Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

## Part 3 – CMT payable

| | | | | |
|---|---|---|---|---|
| Adjusted net income for CMT purposes (line 490 in Part 2, if positive) | 515 | | 158,000 | |
| **Deduct:** | | | | |
| CMT loss available (amount R from Part 7) | | 2,632,765 | | |
| **Minus:** Adjustment for an acquisition of control * | 518 | | | |
| Adjusted CMT loss available | | 2,632,765 | 2,632,765 | C |
| Net income subject to CMT calculation (if negative, enter "0") | 520 | | | |

Amount from line 520 ______ x (Number of days in the tax year before July 1, 2010 ______ / Number of days in the tax year 304) x 4 % = ______ 1

Amount from line 520 ______ x (Number of days in the tax year after June 30, 2010 304 / Number of days in the tax year 304) x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ 3

| | | | |
|---|---|---|---|
| Gross CMT: amount on line 3 above x OAF ** | 540 | | |
| **Deduct:** | | | |
| Foreign tax credit for CMT purposes *** | 550 | | |
| CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") | | | D |
| **Deduct:** | | | |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 136,733 | |
| Net CMT payable (if negative, enter "0") | | | E |

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** ______ / Taxable income ***** ______ = ______

**Ontario allocation factor** 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

## Part 4 – Calculation of CMT credit carryforward

| | | | | |
|---|---|---|---|---|
| CMT credit carryforward at the end of the previous tax year * | | G | | |
| **Deduct:** | | | | |
| CMT credit expired * | 600 | | | |
| CMT credit carryforward at the beginning of the current tax year * (see note below) | | | 620 | |
| **Add:** | | | | |
| CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) | | | 650 | |
| CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) | | | | H |
| **Deduct:** | | | | |
| CMT credit deducted in the current tax year (amount P from Part 5) | | | | I |
| Subtotal (amount H **minus** amount I) | | | | J |
| **Add:** | | | | |
| Net CMT payable (amount E from Part 3) | | | | |
| SAT payable (amount O from Part 6 of Schedule 512) | | | | |
| Subtotal | | | | K |
| CMT credit carryforward at the end of the tax year (amount J **plus** amount K) | | | 670 | L |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

**Note:** If you entered an amount on line 620 or line 650, complete Part 6.

## Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

| | | | | |
|---|---|---|---|---|
| CMT credit available for the tax year (amount H from Part 4) | | | | M |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 136,733 1 | | |
| For a corporation that is not a life insurance corporation: | | | | |
| CMT after foreign tax credit deduction (amount D from Part 3) | 2 | | | |
| For a life insurance corporation: | | | | |
| Gross CMT (line 540 from Part 3) | 3 | | | |
| Gross SAT (line 460 from Part 6 of Schedule 512) | 4 | | | |
| The **greater** of amounts 3 and 4 | 5 | | | |
| **Deduct:** line 2 or line 5, whichever applies: | | 6 | | |
| Subtotal (if negative, enter "0") | | 136,733 | 136,733 | N |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 136,733 | | |
| **Deduct:** | | | | |
| Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) | | 31,687 | | |
| Subtotal (if negative, enter "0") | | 105,046 | 105,046 | O |
| CMT credit deducted in the current tax year (least of amounts M, N, and O) | | | | P |

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

## Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | CMT credit balance * |
|---|---|
| 10th previous tax year | 680 |
| 9th previous tax year | 681 |
| 8th previous tax year | 682 |
| 7th previous tax year | 683 |
| 6th previous tax year | 684 |
| 5th previous tax year | 685 |
| 4th previous tax year | 686 |
| 3rd previous tax year | 687 |
| 2nd previous tax year | 688 |
| 1st previous tax year | 689 |
| Total ** | |

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

## Part 7 – Calculation of CMT loss carryforward

| | | | | |
|---|---|---|---|---|
| CMT loss carryforward at the end of the previous tax year * | | 2,632,765 Q | | |
| **Deduct:** | | | | |
| CMT loss expired * | 700 | | | |
| CMT loss carryforward at the beginning of the tax year * (see note below) | | 2,632,765 | 720 | 2,632,765 |
| **Add:** | | | | |
| CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) | | | 750 | |
| CMT loss available (line 720 **plus** line 750) | | | | 2,632,765 R |
| **Deduct:** | | | | |
| CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) | | | | 158,000 |
| Subtotal (if negative, enter "0") | | | | 2,474,765 S |
| **Add:** | | | | |
| Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) | | | 760 | |
| CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) | | | 770 | 2,474,765 T |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

**Note:** If you entered an amount on line 720 or line 750, complete Part 8.

## Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | Balance earned in a tax year ending before March 23, 2007 * | Balance earned in a tax year ending after March 22, 2007 ** |
|---|---|---|
| 10th previous tax year | 810 | 820 |
| 9th previous tax year | 811 | 821 |
| 8th previous tax year | 812 | 822 |
| 7th previous tax year | 813 | 823 |
| 6th previous tax year | 814 | 824 |
| 5th previous tax year | 815 | 825 |
| 4th previous tax year | 816 | 826 |
| 3rd previous tax year | 817 | 827 |
| 2nd previous tax year | 818 | 828 |
| 1st previous tax year | | 829 |
| Total *** | | |

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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**SCHEDULE 511**

# ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 1 | HYDRO ONE LIMITED | 80512 9962 RC0001 | 0 | 0 |
| 2 | HYDRO ONE INC. | 86999 4731 RC0001 | 0 | 0 |
| 3 | 2486267 ONTARIO INC | 80232 6124 RC0001 | 0 | 0 |
| 4 | 2486268 ONTARIO INC | 80167 4078 RC0001 | 0 | 0 |
| 5 | HYDRO ONE NETWORKS INC. | 87086 5821 RC0001 | 10,000,000,000 | 5,000,000,000 |
| 6 | HYDRO ONE TELECOM INC. | 86800 1066 RC0001 | 0 | 0 |
| 7 | HYDRO ONE TELECOM LINK LIMITED | 88786 7513 RC0001 | 0 | 0 |
| 8 | MUNICIPAL BILLING SERVICES INC | 87560 6519 RC0001 | 0 | 0 |
| 9 | HYDRO ONE LAKE ERIE LINK MANAGEMENT INC | 87892 1519 RC0002 | 0 | 0 |
| 10 | 1938454 ONTARIO INC. | 86391 7795 RC0002 | 0 | 0 |
| 11 | 1943404 ONTARIO INC. | 86248 6123 RC0002 | 0 | 0 |
| 12 | B2M GP INC. | 81838 1840 RC0001 | 0 | 0 |
| 13 | HYDRO ONE B2M HOLDINGS INC | 82217 7531 RC0001 | 0 | 0 |
| 14 | HYDRO ONE B2M LP INC. | 81838 2046 RC0001 | 0 | 0 |
| 15 | NORFOLK ENERGY INC | 86289 0399 RC0001 | 0 | 0 |
| 16 | NORFOLK POWER DISTRIBUTION INC | 86289 2593 RC0001 | 0 | 0 |
| 17 | HALDIMAND COUNTY ENERGY INC | 89076 2412 RC0001 | 0 | 0 |
| 18 | HALDIMAND COUNTY HYDRO INC | 89075 9814 RC0001 | 0 | 0 |
| 19 | Woodstock Hydro Services Inc. | 89909 5012 RC0001 | 0 | 0 |
| 20 | Woodstock Hydro Holdings Inc. | 86248 6123 RC0001 | 0 | 0 |
| 21 | 1908872 ONTARIO INC. | 82581 6838 RC0001 | 0 | 0 |
| 22 | 1908873 ONTARIO INC. | 83392 0978 RC0001 | 0 | 0 |
| 23 | 1937672 ONTARIO INC. | 81722 4561 RC0001 | 0 | 0 |
| 24 | 1937680 ONTARIO INC. | 81930 4924 RC0001 | 0 | 0 |
| 25 | 1937681 ONTARIO INC. | 81722 4363 RC0001 | 0 | 0 |
| 26 | Hydro One Brampton Networks Inc. | 86486 7635 RC0001 | 0 | 0 |

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 27 | HYDRO ONE EAST-WEST TIE INC. | 80105 5880 RC0001 | 0 | 0 |
| | | **Total** | 450 10,000,000,000 | 550 5,000,000,000 |

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency | Agence du revenu du Canada

**SCHEDULE 546**

# *CORPORATIONS INFORMATION ACT* ANNUAL RETURN FOR ONTARIO CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

## Part 1 – Identification

**100** Corporation's name (exactly as shown on the MGS public record)
Hydro One Remote Communities Inc.

| Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent | **110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day) | **120** Ontario Corporation No. |
|---|---|---|
| Ontario | 1998-08-18 | 1310735 |

## Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

**200** Care of (if applicable)

| **210** Street number | **220** Street name/Rural route/Lot and Concession number | **230** Suite number |
|---|---|---|
| 483 | Bay Street 8th Floor | |

**240** Additional address information if applicable (line 220 must be completed first)
South Tower

| **250** Municipality (e.g., city, town) | **260** Province/state | **270** Country | **280** Postal/zip code |
|---|---|---|---|
| Toronto | ON | CA | M5G 2P5 |

## Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

**300** 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

## Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

**450** BARAGETTI (Last name) **451** GIOVANNA (First name)

**454** ______________________, (Middle name(s))

**460** 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

**Complete the applicable parts to report changes in the information recorded on the MGS public record.**

## Part 5 – Mailing address

**500** 1 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

**510** Care of (if applicable)

**520** Street number **530** Street name/Rural route/Lot and Concession number **540** Suite number

**550** Additional address information if applicable (line 530 must be completed first)

**560** Municipality (e.g., city, town) **570** Province/state **580** Country **590** Postal/zip code

## Part 6 – Language of preference

**600** 1 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 550**

# ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

| 110 Name of person to contact for more information | 120 Telephone number including area code |
|---|---|
| Glendy Cheung | (416) 345-6812 |

Is the claim filed for a CETC earned through a partnership?* . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . **160** ____________

Enter the percentage of the partnership's CETC allocated to the corporation . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

## Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 10,826,578

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \ \textbf{minus} \ \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \ \textbf{minus} \ \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

| | A<br>Name of university, college, or other eligible educational institution<br>**400** | B<br>Name of qualifying co-operative education program<br>**405** |
|---|---|---|
| 1. | McMaster University | Mechanical Engineering |
| 2. | McMaster University | Mechanical Engineering |
| 3. | University of Toronto | Mechanical Engineering |

| | C<br>Name of student<br>**410** | D<br>Start date of WP (see note 1 below)<br>**430** | E<br>End date of WP (see note 2 below)<br>**435** |
|---|---|---|---|
| 1. | [redacted] | 2015-01-01 | 2015-04-30 |
| 2. | [redacted] | 2015-05-01 | 2015-08-28 |
| 3. | [redacted] | 2015-05-04 | 2015-08-31 |

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

## Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

| | F1<br>Eligible expenditures before March 27, 2009 (see note 1 below)<br>450 | Eligible percentage before March 27, 2009 (from line 310 in Part 3) | F2<br>Eligible expenditures after March 26, 2009 (see note 1 below)<br>452 | Eligible percentage after March 26, 2009 (from line 310a in Part 3) | X<br>Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below) | Y<br>Total number of consecutive weeks of the student's WP (see note 3 below) |
|---|---|---|---|---|---|---|
| 1. | | 10.000 % | 25,174 | 25.000 % | | 16 |
| 2. | | 10.000 % | 25,174 | 25.000 % | | 17 |
| 3. | | 10.000 % | 20,866 | 25.000 % | | 17 |

| | G<br>Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below)<br>460 | H<br>Maximum CETC per WP (see note 3 below)<br>462 | I<br>CETC on eligible expenditures (column G or H, whichever is less)<br>470 | J<br>CETC on repayment of government assistance (see note 4 below)<br>480 | K<br>CETC for each WP (column I or column J)<br>490 |
|---|---|---|---|---|---|
| 1. | 6,294 | 3,000 | 3,000 | | 3,000 |
| 2. | 6,294 | 3,000 | 3,000 | | 3,000 |
| 3. | 5,217 | 3,000 | 3,000 | | 3,000 |

**Ontario co-operative education tax credit** (total of amounts in column K) 500 9,000 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = . . . . . . . . . . . . . . . . . . . . . . . ________ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 552**

# Ontario Apprenticeship Training Tax Credit

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-10-31 |

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  – paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  – for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  – for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  – the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  – it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  – the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  – the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

**110** Name of person to contact for more information: Glendy Cheung

**120** Telephone number: (416) 345-6812

Is the claim filed for an ATTC earned through a partnership? * . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

## Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 10,826,528

**For eligible expenditures incurred before March 27, 2009:**

- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[ 5\,\% \times \frac{(\text{amount on line 300 minus } 400{,}000)}{200{,}000} \right]$$

**Specified percentage** . . . . . **310** 25.000 %

**For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:**

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 35\,\% + \left[ 10\,\% \times \left[ 1 - \frac{(\text{amount on line 300 minus } 400{,}000)}{200{,}000} \right] \right]$$

**Specified percentage** . . . . . **312** 35.000 %

**For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:**

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 25\,\% + \left[ 5\,\% \times \left[ 1 - \frac{(\text{amount on line 300 minus } 400{,}000)}{200{,}000} \right] \right]$$

**Specified percentage** . . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

| | A<br>Trade code<br>400 | B<br>Apprenticeship program/trade name<br>405 | C<br>Name of apprentice<br>410 |
|---|---|---|---|
| 1. | 434a | Powerline Technician | [redacted] |
| 2. | 310t | Truck And Coach Technician | [redacted] |
| 3. | 310t | Truck And Coach Technician | [redacted] |
| 4. | 434a | Powerline Technician | [redacted] |
| 5. | 310t | Truck And Coach Technician | [redacted] |
| 6. | 310t | Truck And Coach Technician | [redacted] |
| 7. | 310t | Truck And Coach Technician | [redacted] |
| 8. | 309a | Electrician-Construction and Maintenance | [redacted] |
| 9. | 310t | Truck And Coach Technician | [redacted] |
| 10. | | | |
| 11. | | | |

| | D<br>Original contract or training agreement number<br>420 | E<br>Original registration date of apprenticeship contract or training agreement (year month day) (see note 1)<br>425 | F<br>Start date of employment as an apprentice in the tax year (year month day) (see note 2)<br>430 | G<br>End date of employment as an apprentice in the tax year (year month day) (see note 3)<br>435 |
|---|---|---|---|---|
| 1. | [redacted] | 2012-02-27 | 2015-08-03 | 2015-10-31 |
| 2. | [redacted] | 2013-01-28 | 2015-10-05 | 2015-10-31 |
| 3. | [redacted] | 2013-01-28 | 2015-01-07 | 2015-02-02 |
| 4. | [redacted] | 2013-01-28 | 2015-01-05 | 2015-07-31 |
| 5. | [redacted] | 2013-01-28 | 2015-06-29 | 2015-10-26 |
| 6. | [redacted] | 2013-01-28 | 2015-07-06 | 2015-09-23 |
| 7. | [redacted] | 2012-05-28 | 2015-03-30 | 2015-06-25 |
| 8. | [redacted] | 2012-06-03 | 2015-06-01 | 2015-10-31 |
| 9. | [redacted] | 2013-01-28 | 2015-01-01 | 2015-02-04 |
| 10. | | | | |
| 11. | | | | |

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

## Part 4 – Ontario apprenticeship training tax credit (continued)

| | H1<br>Number of days employed as an apprentice in the tax year before March 27, 2009<br>441 | H2<br>Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1)<br>442 | 4H<br>Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) | H3<br>Number of days employed as an apprentice in the tax year (column H1 **plus** column H2)<br>440 | I<br>Maximum credit amount for the tax year (see note 2)<br>445 |
|---|---|---|---|---|---|
| 1. | | 90 | | 90 | 2,466 |
| 2. | | 27 | | 27 | 740 |
| 3. | | 27 | | 27 | 740 |
| 4. | | 208 | | 208 | 5,699 |
| 5. | | 120 | | 120 | 3,288 |
| 6. | | 80 | | 80 | 2,192 |
| 7. | | 88 | | 88 | 2,411 |
| 8. | | 153 | | 153 | 4,192 |
| 9. | | 35 | | 35 | 959 |
| 10. | | | | | |
| 11. | | | | | |

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E on page 2.
For 4H: The days employed as an apprentice must be within 36 months of the registration date provided in column E on page 2.

Note 2: Maximum credit = ($10,000 × H2/365*) or ($5,000 × 4H/365*), whichever applies.
* 366 days, if the tax year includes February 29

| | J1<br>Eligible expenditures before March 27, 2009<br>451 | J2<br>Eligible expenditures incurred after March 26, 2009 (see note 3)<br>452 | 4J<br>Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) | J3<br>Eligible expenditures for the tax year (column J1 **plus** column J2)<br>450 | K<br>Eligible expenditures multiplied by specified percentage (see note 4)<br>460 |
|---|---|---|---|---|---|
| 1. | | 13,440 | | 13,440 | 4,704 |
| 2. | | 5,786 | | 5,786 | 2,025 |
| 3. | | 6,626 | | 6,626 | 2,319 |
| 4. | | 42,267 | | 42,267 | 14,793 |
| 5. | | 24,755 | | 24,755 | 8,664 |
| 6. | | 20,021 | | 20,021 | 7,007 |
| 7. | | 17,220 | | 17,220 | 6,027 |
| 8. | | 28,239 | | 28,239 | 9,884 |
| 9. | | 8,311 | | 8,311 | 2,909 |
| 10. | | | | | |
| 11. | | | | | |

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.
For 4J: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J2 × line 312) or (4J × line 314), whichever applies.

| | **L** ATTC on eligible expenditures (lesser of columns I and K) **470** | **M** ATTC on repayment of government assistance (see note 5) **480** | **N** ATTC for each apprentice (column L or M, whichever applies) **490** |
|---|---|---|---|
| 1. | 2,466 | | 2,466 |
| 2. | 740 | | 740 |
| 3. | 740 | | 740 |
| 4. | 5,699 | | 5,699 |
| 5. | 3,288 | | 3,288 |
| 6. | 2,192 | | 2,192 |
| 7. | 2,411 | | 2,411 |
| 8. | 4,192 | | 4,192 |
| 9. | 959 | | 959 |
| 10. | | | |
| 11. | | | |

**Ontario apprenticeship training tax credit** (total of amounts in column N) **500** 22,687 **O**

**Or**, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = . . . . . . . . . . . . . . . . ______ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

Canada Revenue Agency | Agence du revenu du Canada

# T2 Corporation Income Tax Return

**200**

**055** **Do not use this area**

Filed: 2017-08-28
EB-2017-0051
Exhibit D2-09-01
Attachment 4
Page 1 of 62

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

## Identification

**Business number (BN)** . . . . . . . . . . **001** 87083 6269 RC0001

**Corporation's name**

**002** Hydro One Remote Communities Inc.

**Address of head office**

Has this address changed since the last time we were notified? . . . . . . . . . . . . **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

**011** 483 BAY STREET 8TH FLOOR

**012** SOUTH TOWER

| City | Province, territory, or state |
|---|---|
| **015** TORONTO | **016** ON |
| Country (other than Canada) | Postal code/Zip code |
| **017** | **018** M5G 2P5 |

**Mailing address** (if different from head office address)

Has this address changed since the last time we were notified? . . . . . . . . . . . **020** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

**021** c/o GIOVANNA BARAGETTI

**022** 483 BAY STREET 7TH FLOOR

**023** SOUTH TOWER

| City | Province, territory, or state |
|---|---|
| **025** TORONTO | **026** ON |
| Country (other than Canada) | Postal code/Zip code |
| **027** | **028** M5G 2P5 |

**Location of books and records** (if different from head office address)

Has the location of books and records changed since the last time we were notified? . . . . . . . . . . . . . . . . . . . . . **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

**031** 483 BAY STREET 7TH FLOOR

**032** SOUTH TOWER

| City | Province,territory, or state |
|---|---|
| **035** TORONTO | **036** ON |
| Country (other than Canada) | Postal code/Zip code |
| **037** | **038** M5G 2P5 |

**040** **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . . . . . . . . . . **043** YYYY MM DD

**To which tax year does this return apply?**

Tax year start **060** 2015-11-01 (YYYY MM DD)
Tax year-end **061** 2015-11-04 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . . . . . **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . . . . . . . . . . **065** YYYY MM DD

**Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)?** . . . . . . . . . . . . **066** 1 Yes [X] 2 No [ ]

**Is the corporation a professional corporation that is a member of a partnership?** . . . . . . . . . . . . . . . . . **067** 1 Yes [ ] 2 No [X]

**Is this the first year of filing after:**

Incorporation? . . . . . . . . . . . . . . . **070** 1 Yes [ ] 2 No [X]
Amalgamation? . . . . . . . . . . . . . . . **071** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . . **072** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . **076** 1 Yes [ ] 2 No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . . **078** 1 Yes [ ] 2 No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . **079**

**Is the corporation a resident of Canada?**

**080** 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

**081**

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . **082** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**

**085**
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

**Do not use this area**

**095** **096** **898**

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| Is the corporation an associated CCPC? | | X | 23 |
| Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders who own voting shares? | 151 | | 19 |
| Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership account number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation own any shares in one or more foreign affiliates in the tax year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*? | 170 | | 29 |
| Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | X | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | ——— |
| Does the corporation earn income from one or more Internet webpages or websites? | 180 | | 88 |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine? | 202 | | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | X | 3 |
| Is the corporation claiming any type of losses? | 204 | | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | | 6 |
| i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440? | 207 | | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any property that is eligible capital property? | 210 | X | 10 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)? | 213 | | 13 |
| Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits? | 221 | | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | | 31 |
| Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | | 33/34/35 |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | | ——— |
| Is the corporation claiming a surtax credit? | 237 | | 37 |
| Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II - Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit refund? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit refund? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments – continued from page 2

| | | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates in the tax year? | 271 | | T1134 |
| Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | X | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | X | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| | | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | | X |
| Is the corporation inactive? | 280 | | X |

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

| | | | |
|---|---|---|---|
| 284 | Electricity generation and distribution | 285 | 100.000 % |
| 286 | | 287 | % |
| 288 | | 289 | % |

| | | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | | X |
| Did the corporation emigrate from Canada during the tax year? | 292 | | X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | | |

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ________ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

## Taxable income

| | | | | |
|---|---|---|---|---|
| Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. | 300 | | 3,293 | A |
| **Deduct:** Charitable donations from Schedule 2 | 311 | | | |
| Gifts to Canada, a province, or a territory from Schedule 2 | 312 | | | |
| Cultural gifts from Schedule 2 | 313 | | | |
| Ecological gifts from Schedule 2 | 314 | | | |
| Gifts of medicine from Schedule 2 | 315 | | | |
| Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | | | |
| Part VI.1 tax deduction* | 325 | | | |
| Non-capital losses of previous tax years from Schedule 4 | 331 | | | |
| Net capital losses of previous tax years from Schedule 4 | | | | |
| Restricted farm losses of previous tax years from Schedule 4 | 333 | | | |
| Farm losses of previous tax years from Schedule 4 | 334 | | | |
| Limited partnership losses of previous tax years from Schedule 4 | 335 | | | |
| Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | |
| Prospector's and grubstaker's shares | 350 | | | |
| Subtotal | | | | B |
| Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | 3,293 | C |
| **Add:** Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | 355 | | | D |
| **Taxable income** (amount C **plus** amount D) | 360 | | 3,293 | |
| Income exempt under paragraph 149(1)(t) | 370 | | | |
| **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | 3,293 | Z |

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

Income from active business carried on in Canada from Schedule 7 . . . . . . . . . . . . **400** 3,293 A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . . . . . . . . **405** 3,293 B

Business limit (see notes 1 and 2 below) . . . . . . . . . . . . **410** C

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction:**

Amount C ______ x **415** *** ______ D / 11,250 = . . . . . . . . . . . . ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . . . . . . . . **425** ______ F

**Small business deduction**

Amount A, B, C, or F, whichever is the least ______ x Number of days in the tax year before January 1, 2016 / Number of days in the tax year 4 / 4 x 17 % = ______ 1

Amount A, B, C, or F, whichever is the least ______ x Number of days in the tax year after December 31, 2015, and before January 1, 2017 / Number of days in the tax year ______ / 4 x 17.5 % = ______ 2

Total of amounts 1 and 2 (enter amount G on line I on page 7) **430** ______ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | 3,293 | A |
| Lesser of amounts B9 and H9 from Part 9 of Schedule 27 | | B | | |
| Amount K13 from Part 13 of Schedule 27 | | C | | |
| Personal service business income **432** | | D | | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | E | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | F | | |
| Aggregate investment income from line 440 on page 6* | | G | | |
| Subtotal (**add** amounts B to G) | | | | H |
| Amount A **minus** amount H (if negative, enter "0") | | | 3,293 | I |
| **General tax reduction for Canadian-controlled private corporations** – Amount I **multiplied** by 13 % | | | 428 | J |

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | K |
| Lesser of amounts B9 and H9 from Part 9 of Schedule 27 | | L | | |
| Amount K13 from Part 13 of Schedule 27 | | M | | |
| Personal service business income **434** | | N | | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | O | | |
| Subtotal (**add** amounts L to O) | | | | P |
| Amount K **minus** amount P (if negative, enter "0") | | | | Q |
| **General tax reduction** – Amount Q **multiplied** by 13 % | | | | R |

Enter amount R on line 639 on page 7.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

Aggregate investment income from Schedule 7 . . . . . . . . **440** ________ x ( 26 2 / 3 + 4 x (Number of days in the tax year after 2015 ______ / Number of days in the tax year 4 ) % = ________ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . . . . . . . . . . . . . . . . . . . . ________ B

**Deduct:**
Foreign investment income from Schedule 7 . . . . . **445** ________ x ( 9 1 / 3 – 1 1 / 3 x (Number of days in the tax year after 2015 ______ / Number of days in the tax year 4 ) % = ________

(if negative, enter "0") ________ ________ D

Amount A **minus** amount D (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ E

Taxable income from line 360 on page 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 3,293 F

**Deduct:**
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ G

Foreign non-business income tax credit from line 632 on page 7 . . . . ________ x 100 / 35 = ________ H

Foreign business income tax credit from line 636 on page 7 . . . . . . . . . . . . . ________ x 4 = ________ I

Subtotal ________ ________ J

3,293 K

x ( 26 2 / 3 + 4 x (Number of days in the tax year after 2015 ______ / Number of days in the tax year 4 ) % = 878 L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . . . . . . . . . . . . . . . . . . . . 494 M

**Refundable portion of Part I tax** – Amount E, L, or M, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . **450** ________ N

## Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . . . . . . . . . . . . . . **460** ________

**Deduct:** Dividend refund for the previous tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **465** ________

________ ________ O

**Add** the total of:

Refundable portion of Part I tax from line 450 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ P

Total Part IV tax payable from Schedule 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . . . . . . . . . . . . . . . . . . . . **480** ________

________ ________ R

**Refundable dividend tax on hand at the end of the tax year** – Amount O **plus** amount R . . . . . . . . . . . . . . . . . . . . . **485** ________

## Dividend refund

**Private and subject corporations at the time taxable dividends were paid in the tax year**

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . . . . . . . . . . . . . . . . . . 35,000,000 x [ ( 1 / 3 ) + ( 5 x (Number of days in the tax year after 2015 ______ / Number of days in the tax year 4 ) % ] = 11,666,667 S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ T

**Dividend refund** – Amount S or T, whichever is less . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ U

Enter amount U on line 784 on page 8.

## Part I tax

| | | | | | |
|---|---|---|---|---|---|
| Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % | | | 550 | 1,251 | A |
| Recapture of investment tax credit from Schedule 31 | | | 602 | | B |

**Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income**
(if it was a CCPC throughout the tax year)

| | | | | |
|---|---|---|---|---|
| Aggregate investment income from line 440 on page 6 | | | | C |
| Taxable income from line 360 on page 3 | 3,293 | D | | |
| **Deduct:** | | | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | E | | |
| Net amount (amount D **minus** amount E) | 3,293 | | 3,293 | F |

**Refundable tax on CCPC's investment income** –

( 6 2 / 3 + 4 x ______ ) % of whichever is less: amount C or amount F . . . 604 ______ G

(Number of days in the tax year after 2015 / Number of days in the tax year; 4)

Subtotal (**add** amounts A, B, and G) 1,251 H

**Deduct:**

| | | | | |
|---|---|---|---|---|
| Small business deduction from line 430 on page 4 | | | I | |
| Federal tax abatement | 608 | 329 | | |
| Manufacturing and processing profits deduction from Schedule 27 | 616 | | | |
| Investment corporation deduction | 620 | | | |
| Taxed capital gains 624 | | | | |
| Additional deduction – credit unions from Schedule 17 | 628 | | | |
| Federal foreign non-business income tax credit from Schedule 21 | 632 | | | |
| Federal foreign business income tax credit from Schedule 21 | 636 | | | |
| General tax reduction for CCPCs from amount J on page 5 | 638 | 428 | | |
| General tax reduction from amount R on page 5 | 639 | | | |
| Federal logging tax credit from Schedule 21 | 640 | | | |
| Eligible Canadian bank deduction under section 125.21 | 641 | | | |
| Federal qualifying environmental trust tax credit | 648 | | | |
| Investment tax credit from Schedule 31 | 652 | | | |
| Subtotal | | 757 | 757 | J |

**Part I tax payable** – Amount H **minus** amount J . . . 494 K
Enter amount K on line 700 on page 8.

## Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **http://www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, personal information bank CRA PPU 047.

## Summary of tax and credits

**Federal tax**

| | | |
|---|---|---|
| Part I tax payable from amount K on page 7 | 700 | 494 |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | 494 |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | | |
|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | 379 |
| Total tax payable | 770 | 873 A |

**Deduct other credits:**

| | | |
|---|---|---|
| Investment tax credit refund from Schedule 31 | 780 | |
| Dividend refund from amount U on page 6 | 784 | |
| Federal capital gains refund from Schedule 18 | 788 | |
| Federal qualifying environmental trust tax credit refund | 792 | |
| Canadian film or video production tax credit refund (Form T1131) | 796 | |
| Film or video production services tax credit refund (Form T1177) | 797 | |
| Tax withheld at source | 800 | |
| Total payments on which tax has been withheld | 801 | |
| Provincial and territorial capital gains refund from Schedule 18 | 808 | |
| Provincial and territorial refundable tax credits from Schedule 5 | 812 | |
| Tax instalments paid | 840 | |
| Total credits | 890 | B |

Refund code 894 Overpayment

Balance (amount A **minus** amount B) 873

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . . 873

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920

## Certification

I, 950 BARAGETTI (Last name (print)) 951 GIOVANNA (First name (print)) 954 Vice President, Corporate Tax (Position, office, or rank),
am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2016-04-29 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (416) 345-6778 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☐ 2 No ☒

958 GLENDY CHEUNG (Name (print)) 959 (416) 345-6812 (Telephone number)

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 100**

Form identifier 100

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

## Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 12,280,000 | 9,423,000 |
| | Total tangible capital assets | 2008 | + | 68,581,000 | 68,581,000 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 26,032,000 | 25,986,000 |
| | Total intangible capital assets | 2178 | + | | |
| | Total accumulated amortization of intangible capital assets | 2179 | – | | |
| | Total long-term assets | 2589 | + | 20,236,000 | 20,210,000 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 75,065,000 | 72,228,000 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 15,430,000 | 17,593,000 |
| | Total long-term liabilities | 3450 | + | 60,179,000 | 60,179,000 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 75,609,000 | 77,772,000 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | -544,000 | -5,544,000 |
| | **Total liabilities and shareholder equity** | 3640 | = | 75,065,000 | 72,228,000 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | -5,000,000 | -5,000,000 |

* Generic item

Canada Revenue Agency — Agence du revenu du Canada

**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | Ontario Hydro Remote Communities Service Company Inc. |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Income statement information** | | | | |
| | Total sales of goods and services | 8089 | + | 690,000 | 39,985,000 |
| | Cost of sales | 8518 | – | 271,000 | 18,714,000 |
| | **Gross profit/loss** | 8519 | = | 419,000 | 21,271,000 |
| | Cost of sales | 8518 | + | 271,000 | 18,714,000 |
| | Total operating expenses | 9367 | + | 419,000 | 21,113,000 |
| | **Total expenses** (mandatory field) | 9368 | = | 690,000 | 39,827,000 |
| | Total revenue (mandatory field) | 8299 | + | 690,000 | 39,985,000 |
| | Total expenses (mandatory field) | 9368 | – | 690,000 | 39,827,000 |
| | **Net non-farming income** | 9369 | = | | 158,000 |
| | **Farming income statement information** | | | | |
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | | 158,000 |
| | **Total other comprehensive income** | 9998 | = | | 12,000 |
| | **Extraordinary items and income (linked to Schedule 140)** | | | | |
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | | 5,158,000 |
| | Future (deferred) income tax provision | 9995 | – | | |
| | Total – Other comprehensive income | | + | | 12,000 |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | | = | | -4,988,000 |

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 141**

# Notes Checklist

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [X] 2 No [ ]

**Note**
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 [ ]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

## Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [ ]

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: . . . . . **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . 1 Yes [ ] 2 No [X]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [ ] 2 No [X]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . 1 Yes [ ] 2 No [X]

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income<br>Increase (decrease) | | In OCI<br>Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

# T2 BAR CODE RETURN

**Name: Hydro One Remote Communities Inc.**

**BN: 87083 6269 RC 0001**

**Tax Year Start: 2015-11-01**

**Tax Year End: 2015-11-04**

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and was wholly owned by the Province of Ontario (the Province) until October 31, 2015. On October 31, 2015, Hydro One Limited, a wholly owned subsidiary of the Province, acquired all issued and outstanding shares of Hydro One from the Province. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the Business Corporations Act (Ontario) and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. These Financial Statements have been prepared for the purpose of filing the Company's income tax return, as on November 5, 2015, the common shares of Hydro One Limited began trading on the Toronto Stock Exchange, and as a result, the Company lost its status as a Canadian-

Controlled Private Corporation. As these financial statements have not been prepared for general purposes, some users may require additional information. These Financial Statements present the financial position of the Company at November 4, 2015 and the results of its operations and its cash flows for the period from November 1, 2015 to November 4, 2015. The comparative information is presented as at October 31, 2015 and for the period from January 1, 2015 to October 31, 2015.

The Company uses a cost recovery model applied to achieve breakeven net income. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. For the comparative period from January 1 to October 31, 2015, the Company has reported a net loss due to recognition of tax expense resulting from the Company no longer being exempt from tax under the Federal Tax Regime. This tax is not recovered from ratepayers as it is funded by the Company's shareholder, and therefore, it is not included in the cost recovery model applied to achieve breakeven net income.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairment, contingencies, unbilled revenue, allowance for doubtful accounts 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.

Rate Setting

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

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

Revenue Recognition

Revenues attributable to the generation and 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 RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity

System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are 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.

Long-term accounts receivable are recorded at their invoiced amount and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. Provision for uncollectible amounts for this component is set at the inception of the balance and is maintained until settlement of those amounts. The provision for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

Income Taxes

On October 31, 2015, the Company ceased to be exempt from tax under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) (Federal Tax Regime). Prior to that date, Hydro One Remote Communities was required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the Electricity Act, 1998 (Ontario) (PILs Regime). These payments were 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. Upon exiting the PILs Regime, Hydro One Remote Communities 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 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 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 Statements of Operations and Comprehensive Income (Loss).

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.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter -company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash 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%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. 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 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

Generation

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

Distribution

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

Administration and Service

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

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 (Loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

# T2 BAR CODE RETURN

**Name: Hydro One Remote Communities Inc.**

**BN: 87083 6269 RC 0001**
**Tax Year Start: 2015-11-01**
**Tax Year End: 2015-11-04**

Construction in Progress

Construction 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

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category.

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

| | | | |
|---|---|---|---|
| Generation | 20 years | 3% - 7% | 5% |
| Distribution | 45 years | 1% - 7% | 2% |
| Administration and service | 36 years | 3% - 20% | 4% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 assets where no asset retirement obligation 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 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.

The carrying costs of most of Hydro One Remote Communities' 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. As at November 4, 2015 and October 31, 2015, no asset impairment had been recorded.

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 Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income (Loss). 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents OCI and net income in a single continuous Statement of Operations and

Comprehensive Income (Loss).

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.

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.

Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at November 4, 2015 and October 31, 2015. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's 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 plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets 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. The measurement date for all plans is December 31.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit 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, 2015.

Post-retirement and post-employment benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of the these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's 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 accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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.

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, 2015.

Loss Contingencies

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

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

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement 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 Remote Communities records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

# T2 BAR CODE RETURN

**Name: Hydro One Remote Communities Inc.**

**BN: 87083 6269 RC 0001**

**Tax Year Start: 2015-11-01**

**Tax Year End: 2015-11-04**

**SCHEDULE 100**

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

## Assets – lines 1000 to 2599

| | | | | | |
|---|---|---|---|---|---|
| 1062 | 3,834,000 | 1066 | 2,656,000 | 1122 | 3,043,000 |
| 1480 | 2,627,000 | 1481 | 120,000 | 1599 | 12,280,000 |
| 1740 | 55,044,000 | 1741 | -23,512,000 | 1900 | 11,565,000 |
| 1901 | -2,520,000 | 1920 | 1,972,000 | 2008 | 68,581,000 |
| 2009 | -26,032,000 | 2420 | 15,978,000 | 2421 | 4,258,000 |
| 2589 | 20,236,000 | 2599 | 75,065,000 | | |

## Liabilities – lines 2600 to 3499

| | | | | | |
|---|---|---|---|---|---|
| 2620 | 7,966,000 | 2629 | 752,000 | 2860 | 6,592,000 |
| 2960 | 120,000 | 3139 | 15,430,000 | 3140 | 33,000,000 |
| 3320 | 13,443,000 | 3321 | 13,736,000 | 3450 | 60,179,000 |
| 3499 | 75,609,000 | | | | |

## Shareholder equity – lines 3500 to 3640

| | | | | | |
|---|---|---|---|---|---|
| 3500 | 5,000,000 | 3580 | -544,000 | 3600 | -5,000,000 |
| 3620 | -544,000 | 3640 | 75,065,000 | | |

## Retained earnings – lines 3660 to 3849

| | | | |
|---|---|---|---|
| 3660 | -5,000,000 | 3849 | -5,000,000 |

**SCHEDULE 125**

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

### Description

Operating name . . . . . . . . **0001** Ontario Hydro Remote Communities Service Company Inc.

Sequence number . . . . . . . **0003** 01

### Revenue – lines 8000 to 8299

| | | | | | |
|---|---|---|---|---|---|
| 8000 | 690,000 | 8089 | 690,000 | 8299 | 690,000 |

### Cost of sales – lines 8300 to 8519

| | | | | | |
|---|---|---|---|---|---|
| 8408 | 271,000 | 8518 | 271,000 | 8519 | 419,000 |

### Operating expenses – lines 8520 to 9369

| | | | | | |
|---|---|---|---|---|---|
| 8670 | 60,000 | 8714 | 24,000 | 9270 | 335,000 |
| 9367 | 419,000 | 9368 | 690,000 | | |

### Extraordinary items and taxes – lines 9970 to 9999

| | |
|---|---|
| 9999 | 0 |

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# Net Income (Loss) for Income Tax Purposes

**SCHEDULE 1**

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

| | | | | |
|---|---|---|---|---|
| Amount calculated on line 9999 from Schedule 125 | | | 0 | A |
| **Add:** | | | | |
| Amortization of tangible assets | 104 | 60,000 | | |
| Subtotal of additions | | 60,000 ▶ | 60,000 | |
| **Other additions:** | | | | |
| **Miscellaneous other additions:** | | | | |
| 604 | | | | |
| Total | 294 | | | |
| Subtotal of other additions | 199 | 0 | 0 | |
| **Total additions** | 500 | 60,000 | 60,000 | B |
| Amount A **plus** amount B | | | 60,000 | |
| **Deduct:** | | | | |
| Capital cost allowance from Schedule 8 | 403 | 42,707 | | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 13,888 | | |
| Subtotal of deductions | | 56,595 ▶ | 56,595 | |
| **Other deductions:** | | | | |
| **Miscellaneous other deductions:** | | | | |
| 700 S.20(1)(e) deduction | 390 | 112 | | |
| 704 | | | | |
| Total | 394 | | | |
| Subtotal of other deductions | 499 | 112 | 112 | |
| **Total deductions** | 510 | 56,707 | 56,707 | |
| **Net income (loss) for income tax purposes** – enter on line 300 of the T2 return | | | 3,293 | |

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# DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

**SCHEDULE 3**

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A – Enter "X" if dividends received from a foreign source (connected corporation only).
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.
- Column FF – Indicate if the dividends have been received before January 1, 2016, or after December 31, 2015. This information is required to determine the appropriate rate for the Part IV tax calculation.

## Part 1 – Dividends received in the tax year

**Do not include dividends received from foreign non-affiliates.**

| Name of payer corporation (from which the corporation received the dividend) 200 | A | B Enter 1 if payer corporation is connected 205 | C Business Number of connected corporation 210 | D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD (See note) 220 | E Non-taxable dividend under section 83 230 |
|---|---|---|---|---|---|
| | | | | | |

Columns B, C and D: Complete if payer corporation is connected

**Total** (enter on line 402 of Schedule 1)

**Note**: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.
For more details, consult the Help.

| F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240 | F1 Eligible dividends (included in column F) | F2 | FF | G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250 | H Dividend refund of the connected payer corporation (for tax year in column D)** 260 | I Part IV tax before deductions F x rate *** 270 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | J |

Columns G and H: Complete if payer corporation is connected

**Total** (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: $\text{Part IV tax} = \dfrac{\text{Column F} \times \text{Column H}}{\text{Column G}}$

Rate: The Part IV tax rate is 38 1/3% for dividends received after December 31, 2015, and 33 1/3% for dividends received before January 1, 2016.

## Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . . . . . . .

**Deduct:**

Part IV.I tax payable on dividends subject to Part IV tax . . . . . . . . 320

Subtotal

**Deduct:**

Current-year non-capital loss claimed to reduce Part IV tax . . . . . 330

Non-capital losses from previous years claimed to reduce Part IV tax . . . . 335

Current-year farm loss claimed to reduce Part IV tax . . . . . 340

Farm losses from previous years claimed to reduce Part IV tax . . . . 345

Total losses applied against Part IV tax x 1 / 3 =

Part IV tax payable (enter amount on line 712 of the T2 return) . . . . . . . . 360

## Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

| | A | B | C | D | D1 |
|---|---|---|---|---|---|
| | Name of connected recipient corporation 400 | Business Number 410 | Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note) 420 | Taxable dividends paid to connected corporations 430 | Eligible dividends (included in column D) |
| 1 | Hydro One Inc. | 86999 4731 RC0001 | 2015-11-04 | 35,000,000 | |

**Note**

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation. For more details, consult the Help.

**Total** 35,000,000

Total taxable dividends paid in the tax year to other than connected corporations . . . . . . . . 450

Eligible dividends (included in line 450) . . . . . . . . 450a

Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450) . . . . . . . . 460 35,000,000

## Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) . . . . . . 35,000,000

Other dividends paid in the tax year (total of 510 to 540) . . . . . . . .

Total dividends paid in the tax year . . . . . . . . 500 35,000,000

**Deduct:**

Dividends paid out of capital dividend account . . . . . . . . 510

Capital gains dividends . . . . . . . . 520

Dividends paid on shares described in subsection 129(1.2) . . . . . .

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . . . . .

Subtotal

Total taxable dividends paid in the tax year that qualify for a dividend refund . . . . . . . . 35,000,000

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**Schedule 8**

# Capital Cost Allowance (CCA)

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes ☐ 2 No ☒

| | 1 Class number (See Note) 200 | Description | 2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201 | 3 Cost of acquisitions during the year (new property must be available for use)* 203 | 4 Adjustments and transfers** 205 | 5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207 | 6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211 | 7 Reduced undepreciated capital cost | 8 CCA rate % **** 212 | 9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213 | 10 Terminal loss (line 404 of Schedule 1) 215 | 11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217 | 12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | | | 15,342,650 | 0 | 250,549 | 15,092,101 | 4 | 0 | 0 | 6,616 | 15,336,034 |
| 2. | 2 | | | | 91,815 | 0 | | 91,815 | 6 | 0 | 0 | 60 | 91,755 |
| 3. | 3 | | | | 749 | 0 | | 749 | 5 | 0 | 0 | | 749 |
| 4. | 6 | | | | 5,920,147 | 0 | 108,040 | 5,812,107 | 10 | 0 | 0 | 6,369 | 5,913,778 |
| 5. | 8 | | | | 1,089,847 | 0 | 151,381 | 938,466 | 20 | 0 | 0 | 2,057 | 1,087,790 |
| 6. | 10 | | | | 844,719 | 0 | 6,994 | 837,725 | 30 | 0 | 0 | 2,754 | 841,965 |
| 7. | 17 | | | | 16,460,167 | 0 | 407,488 | 16,052,679 | 8 | 0 | 0 | 14,074 | 16,446,093 |
| 8. | 43.1 | | | | 1,273,932 | 0 | 27,010 | 1,246,922 | 30 | 0 | 0 | 4,099 | 1,269,833 |
| 9. | 45 | | | | 2,418 | 0 | | 2,418 | 45 | 0 | 0 | 12 | 2,406 |
| 10. | 47 | | | | 7,649,418 | 0 | 83,849 | 7,565,569 | 8 | 0 | 0 | 6,633 | 7,642,785 |
| 11. | 13 | Bisco Water Well | | 7,854 | 38,711 | 0 | 3,927 | 42,638 | NA | 0 | 0 | 17 | 46,548 |
| 12. | 13 | Hillsport Water Well | | | 39,846 | 0 | | 39,846 | NA | 0 | 0 | 11 | 39,835 |
| 13. | 13 | Oba Water Well | | | 17,999 | 0 | | 17,999 | NA | 0 | 0 | 5 | 17,994 |
| 14. | 94 | Construction in progress | | | 1,904,128 | 0 | | 1,904,128 | 0 | 0 | 0 | | 1,904,128 |
| 15. | 94 | Future use | | | 1,936,342 | 0 | | 1,936,342 | 0 | 0 | 0 | | 1,936,342 |
| 16. | 94 | Land | | | 359,667 | 0 | | 359,667 | 0 | 0 | 0 | | 359,667 |
| 17. | 94 | Landscaping | | | 47,952 | 0 | | 47,952 | 0 | 0 | 0 | | 47,952 |
| | | **Totals** | | 7,854 | 53,020,507 | | 1,039,238 | 51,989,123 | | | | 42,707 | 52,985,654 |

**Note:** Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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**SCHEDULE 9**

# RELATED AND ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

| | Name 100 | Country of residence (other than Canada) 200 | Business number (see note 1) 300 | Relationship code (see note 2) 400 | Number of common shares you own 500 | % of common shares you own 550 | Number of preferred shares you own 600 | % of preferred shares you own 650 | Book value of capital stock 700 |
|---|---|---|---|---|---|---|---|---|---|
| 1. | HYDRO ONE LIMITED | CA | 80512 9962 RC0001 | 3 | | | | | |
| 2. | HYDRO ONE INC. | CA | 86999 4731 RC0001 | 1 | | | | | |
| 3. | 2486267 ONTARIO INC | CA | 80232 6124 RC0001 | 3 | | | | | |
| 4. | 2486268 ONTARIO INC | CA | 80167 4078 RC0001 | 3 | | | | | |
| 5. | HYDRO ONE NETWORKS INC. | CA | 87086 5821 RC0001 | 3 | | | | | |
| 6. | HYDRO ONE TELECOM INC. | CA | 86800 1066 RC0001 | 3 | | | | | |
| 7. | HYDRO ONE TELECOM LINK LIMITED | CA | 88786 7513 RC0001 | 3 | | | | | |
| 8. | MUNICIPAL BILLING SERVICES INC | CA | 87560 6519 RC0001 | 3 | | | | | |
| 9. | HYDRO ONE LAKE ERIE LINK MANAGEMENT INC | CA | 87892 1519 RC0002 | 3 | | | | | |
| 10. | 1938454 ONTARIO INC. | CA | 86391 7795 RC0002 | 3 | | | | | |
| 11. | 1943404 ONTARIO INC. | CA | 86248 6123 RC0002 | 3 | | | | | |
| 12. | B2M GP INC. | CA | 81838 1840 RC0001 | 3 | | | | | |
| 13. | HYDRO ONE B2M HOLDINGS INC | CA | 82217 7531 RC0001 | 3 | | | | | |
| 14. | HYDRO ONE B2M LP INC. | CA | 81838 2046 RC0001 | 3 | | | | | |
| 15. | NORFOLK ENERGY INC | CA | 86289 0399 RC0001 | 3 | | | | | |
| 16. | NORFOLK POWER DISTRIBUTION INC | CA | 86289 2593 RC0001 | 3 | | | | | |
| 17. | HALDIMAND COUNTY ENERGY INC | CA | 89076 2412 RC0001 | 3 | | | | | |
| 18. | HALDIMAND COUNTY HYDRO INC | CA | 89075 9814 RC0001 | 3 | | | | | |
| 19. | Woodstock Hydro Services Inc. | CA | 89909 5012 RC0001 | 3 | | | | | |
| 20. | 1937672 ONTARIO INC. | CA | 81722 4561 RC0001 | 3 | | | | | |
| 21. | 1937680 ONTARIO INC. | CA | 81930 4924 RC0001 | 3 | | | | | |
| 22. | 1937681 ONTARIO INC. | CA | 81722 4363 RC0001 | 3 | | | | | |
| 23. | Hydro One East-West Tie Inc. | CA | 80105 5880 RC0001 | 3 | | | | | |

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.

Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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**SCHEDULE 10**

# CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

## Part 1 – Calculation of current year deduction and carry-forward

| | Line | | | Line | | |
|---|---|---|---|---|---|---|
| **Cumulative eligible capital - Balance at the end of the preceding taxation year** (if negative, enter "0") | | | | 200 | | A |
| **Add:** Cost of eligible capital property acquired during the taxation year | 222 | | | | | |
| Other adjustments | 226 | 24,137,840 | | | | |
| Subtotal (line 222 plus line 226) | | 24,137,840 | x 3 / 4 = 18,103,380 B | | | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 | 228 | | x 1 / 2 = C | | | |
| amount B minus amount C (if negative, enter "0") | | | 18,103,380 | | 18,103,380 | D |
| Amount transferred on amalgamation or wind-up of subsidiary | | | | 224 | | E |
| Subtotal (add amounts A, D, and E) | | | | 230 | 18,103,380 | F |
| **Deduct:** Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year | 242 | | G | | | |
| The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) | 244 | | H | | | |
| Other adjustments | 246 | | I | | | |
| (add amounts G,H, and I) | | | x 3 / 4 = | 248 | | J |
| **Cumulative eligible capital balance** (amount F minus amount J) | | | | | 18,103,380 | K |
| (if amount K is negative, enter "0" at line M and proceed to Part 2) | | | | | | |
| Cumulative eligible capital for a property no longer owned after ceasing to carry on that business | 249 | | | | | |
| amount K | | 18,103,380 | | | | |
| **less** amount from line 249 | | | | | | |
| **Current year deduction** | | 18,103,380 | x 7.00 % = | 250 | 13,888 * | |
| (line 249 plus line 250) (enter this amount at line 405 of Schedule 1) | | | | | 13,888 | |
| | | | | | 13,888 | L |
| **Cumulative eligible capital – Closing balance** (amount K minus amount L) (if negative, enter "0") | | | | 300 | 18,089,492 | M |

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

## Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

| | | | | |
|---|---|---|---|---|
| Amount from line K (show as positive amount) | | | | N |
| Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988 | | **400** | 1 | |
| Total of all amounts which reduced CEC in the current or prior years under subsection 80(7) | | **401** | 2 | |
| Total of CEC deductions claimed for taxation years beginning before July 1, 1988 | **402** | 3 | | |
| Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988 | **408** | 4 | | |
| Line 3 minus line 4 (if negative, enter "0") | | | 5 | |
| Total of lines 1, 2 and 5 | | | 6 | |
| Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400 | | 7 | | |
| Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000 | | 8 | | |
| Subtotal (line 7 plus line 8) | **409** | | 9 | |
| Line 6 minus line 9 (if negative, enter "0") | | | | O |
| Line N minus line O (if negative, enter "0") | | | | P |
| | Line 5 | x 1 / 2 = | | Q |
| Line P minus line Q (if negative, enter "0") | | | | R |
| | Amount R | x 2 / 3 = | | S |
| Amount N or amount O, whichever is less | | | | T |
| **Amount to be included in income** (amount S plus amount T) (enter this amount on line 108 of Schedule 1) | | | **410** | |

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**SCHEDULE 23**

# AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

**Column 1:** Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

**Column 2:** Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

**Column 3:** Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

**Column 4:** Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

**Column 5:** Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

**Column 6:** Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

| Calendar year | Acceptable range |
|---|---|
| 2006 | maximum $300,000 |
| 2007 | $300,001 to $400,000 |

| Calendar year | Acceptable range |
|---|---|
| 2008 | maximum $400,000 |
| 2009 | $400,001 to $500,000 |

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

## Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 Year 2015

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 1 Yes ☐ 2 No ☒

| | 1 Names of associated corporations 100 | 2 Business Number of associated corporations 200 | 3 Association code 300 | 4 Business limit for the year (before the allocation) $ | 5 Percentage of the business limit % 350 | 6 Business limit allocated* $ 400 |
|---|---|---|---|---|---|---|
| 1 | Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 1 | 500,000 | | |
| 2 | HYDRO ONE LIMITED | 80512 9962 RC0001 | 1 | 500,000 | | |
| 3 | HYDRO ONE INC. | 86999 4731 RC0001 | 1 | 500,000 | | |
| 4 | 2486267 ONTARIO INC | 80232 6124 RC0001 | 1 | 500,000 | | |
| 5 | 2486268 ONTARIO INC | 80167 4078 RC0001 | 1 | 500,000 | | |
| 6 | HYDRO ONE NETWORKS INC. | 87086 5821 RC0001 | 1 | 500,000 | 100.0000 | 500,000 |
| 7 | HYDRO ONE TELECOM INC. | 86800 1066 RC0001 | 1 | 500,000 | | |
| 8 | HYDRO ONE TELECOM LINK LIMITED | 88786 7513 RC0001 | 1 | 500,000 | | |
| 9 | MUNICIPAL BILLING SERVICES INC | 87560 6519 RC0001 | 1 | 500,000 | | |
| 10 | HYDRO ONE LAKE ERIE LINK MANAGEMENT IN | 87892 1519 RC0002 | 1 | 500,000 | | |
| 11 | 1938454 ONTARIO INC. | 86391 7795 RC0002 | 1 | 500,000 | | |
| 12 | 1943404 ONTARIO INC. | 86248 6123 RC0002 | 1 | 500,000 | | |
| 13 | B2M GP INC. | 81838 1840 RC0001 | 1 | 500,000 | | |

| | 1 Names of associated corporations 100 | 2 Business Number of associated corporations 200 | 3 Asso-ciation code 300 | 4 Business limit for the year (before the allocation) $ | 5 Percentage of the business limit % 350 | 6 Business limit allocated* $ 400 |
|---|---|---|---|---|---|---|
| 14 | HYDRO ONE B2M HOLDINGS INC | 82217 7531 RC0001 | 1 | 500,000 | | |
| 15 | HYDRO ONE B2M LP INC. | 81838 2046 RC0001 | 1 | 500,000 | | |
| 16 | NORFOLK ENERGY INC | 86289 0399 RC0001 | 1 | 500,000 | | |
| 17 | NORFOLK POWER DISTRIBUTION INC | 86289 2593 RC0001 | 1 | 500,000 | | |
| 18 | HALDIMAND COUNTY ENERGY INC | 89076 2412 RC0001 | 1 | 500,000 | | |
| 19 | HALDIMAND COUNTY HYDRO INC | 89075 9814 RC0001 | 1 | 500,000 | | |
| 20 | Woodstock Hydro Services Inc. | 89909 5012 RC0001 | 1 | 500,000 | | |
| 21 | 1937672 ONTARIO INC. | 81722 4561 RC0001 | 1 | 500,000 | | |
| 22 | 1937680 ONTARIO INC. | 81930 4924 RC0001 | 1 | 500,000 | | |
| 23 | 1937681 ONTARIO INC. | 81722 4363 RC0001 | 1 | 500,000 | | |
| 24 | Hydro One East-West Tie Inc. | 80105 5880 RC0001 | 1 | 500,000 | | |
| | | | | **Total** | 100.0000 | 500,000 A |

**Business limit reduction under subsection 125(5.1) of the ITA**

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (09) Canada

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**SCHEDULE 50**

# SHAREHOLDER INFORMATION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

| | | Provide only one number per shareholder | | | | |
|---|---|---|---|---|---|---|
| | Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100** | Business Number (If a corporation is not registered, enter "NR") **200** | Social insurance number **300** | Trust number **350** | Percentage common shares **400** | Percentage preferred shares **500** |
| 1 | Hydro One Inc. | 86999 4731 RC0001 | | | 100.000 | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |

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**Schedule 53**

# General Rate Income Pool (GRIP) Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

On: 2015-11-04

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

## Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

**2006 addition**

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 . . . . . 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   **If the answer to question 3 is yes, complete Part "GRIP addition for 2006".**

**Change in the type of corporation**

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   **If the answer to question 5 is yes, complete Part 4.**

**Amalgamation (first year of filing after amalgamation)**

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   **If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.**
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   **If the answer to question 7 is yes, complete Part 4.**
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   **If the answer to question 8 is yes, complete Part 3.**

**Winding-up**

9. Has the corporation wound-up a subsidiary in the preceding taxation year? . . . . . ☐ Yes ☒ No
   **If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.**
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    **If the answer to question 10 is yes, complete Part 4.**
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    **If the answer to question 11 is yes, complete Part 3.**

## Part 1 – General rate income pool (GRIP)

| | | | | | |
|---|---|---|---|---|---|
| GRIP at the end of the previous tax year | | | | 100 | 559,108 A |
| Taxable income for the year (DICs enter "0") * | | 110 | 3,293 B | | |
| Income for the credit union deduction * (amount E in Part 3 of Schedule 17) | 120 | | | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * | 130 | | | | |
| For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * | 140 | | | | |
| Subtotal (**add** lines 120, 130, and 140) | | | C | | |
| Income taxable at the general corporate rate (amount B **minus** amount C) (if negative enter "0") | | 150 | 3,293 | | |
| After-tax income (line 150 **multiplied** by 0.72 (the general rate factor for the tax year)) | | | | 190 | 2,371 D |
| Eligible dividends received in the tax year | | 200 | | | |
| Dividends deductible under section 113 received in the tax year | | 210 | | | |
| Subtotal (line 200 **plus** line 210) | | | | | E |
| GRIP addition: | | | | | |
| Becoming a CCPC (from amount PP in Part 4) | | 220 | | | |
| Post-amalgamation (total of amounts EE in Part 3 and amounts PP in Part 4) | | 230 | | | |
| Post-wind-up (total of amounts EE in Part 3 and amounts PP in Part 4) | | 240 | | | |
| Subtotal (**add** lines 220, 230, and 240) | | 290 | | | F |
| Subtotal (**add** amounts A, D, E, and F) | | | | | 561,479 G |
| Eligible dividends paid in the previous tax year | | 300 | | | |
| Excessive eligible dividend designations made in the previous tax year | | 310 | | | |
| (If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.) | | | | | |
| Subtotal (line 300 **minus** line 310) | | | | | H |
| GRIP before adjustment for specified future tax consequences (amount G **minus** amount H) (amount can be negative) | | | | 490 | 561,479 |
| Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2) | | | | 560 | |
| **GRIP at the end of the tax year** (line 490 **minus** line 560) | | | | 590 | 561,479 |

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

**First previous tax year** 2015-10-31

| | | | |
|---|---|---|---|
| Taxable income before specified future tax consequences from the current tax year | | J1 | |
| Enter the following amounts before specified future tax consequences from the current tax year: | | | |
| Income for the credit union deduction (amount E in Part 3 of Schedule 17) | K1 | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less | L1 | | |
| Aggregate investment income (line 440 of the T2 return) | M1 | | |
| Subtotal (**add** amounts K1, L1, and M1) | ▶ | N1 | |
| Subtotal (amount J1 **minus** amount N1) (if negative, enter "0") | | ▶ | O1 |

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S1

Subtotal (**add** amounts Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (amount P1 **minus** amount T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (amount O1 **minus** amount U1) (if negative, enter "0") ______ V1

**GRIP adjustment for specified future tax consequences to the first previous tax year**

(amount V1 **multiplied** by 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** ______

**Second previous tax year** 2014-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ M2

Subtotal (**add** amounts K2, L2, and M2) ______ ▶ ______ N2

Subtotal (amount J2 **minus** amount N2) (if negative, enter "0") ______ ▶ ______ O2

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S2

Subtotal (**add** amounts Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (amount P2 **minus** amount T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (amount O2 **minus** amount U2) (if negative, enter "0") ______ V2

**GRIP adjustment for specified future tax consequences to the second previous tax year**

(amount V2 **multiplied** by 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **520** ______

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

**Third previous tax year** 2013-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ M3

Subtotal (**add** amounts K3, L3, and M3) ______ ▶ ______ N3

Subtotal (amount J3 **minus** amount N3) (if negative, enter "0") ______ ▶ ______ O3

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S3

Subtotal (**add** amounts Q3, R3, and S3) ______ ▶ ______ T3

Subtotal (amount P3 **minus** amount T3) (if negative, enter "0") ______ ▶ ______ U3

Subtotal (amount O3 **minus** amount U3) (if negative, enter "0") ______ V3

**GRIP adjustment for specified future tax consequences to the third previous tax year**
(amount V3 **multiplied by** 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **540** ______

**Total GRIP adjustment for specified future tax consequences to previous tax years:**
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ W

Enter amount W on line 560 in part 1.

## Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

**nb. 1** Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . . . . . . . . . . . . . . . . . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . . . . . . ______ CC

Subtotal (amount BB **minus** amount CC) ______ ▶ ______ DD

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)**
(amount AA **minus** amount DD) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE amounts. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

**nb. 1** Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . . . . . . . ☐ Post wind-up . . . . . . . . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . ______ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . ______ GG

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ a
Net capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ b
Farm losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ c
Restricted farm losses . . . . . . . . . . . . . . . . . . . . . . . ______ d
Limited partnership losses . . . . . . . . . . . . . . . . . . . . ______ e

Subtotal (**add** amounts a to e) ______ ► ______ 1

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ f
Net capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . ______ g
Farm losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ h
Restricted farm losses . . . . . . . . . . . . . . . . . . . . . . . ______ i
Limited partnership losses . . . . . . . . . . . . . . . . . . . . ______ j

Subtotal (**add** amounts f to j) ______ ► ______ 2

Unused and unexpired losses at the end of the corporation's previous/last tax year (amount 1 **minus** amount 2) ______ ► ______ HH

Subtotal (**add** amounts FF, GG, and HH) ______ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . ______ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . ______ KK

All the corporation's reserves deducted in its previous/last tax year . . . . . . . . . . . . . . . . . . . . ______ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ NN

Subtotal (**add** amounts JJ to NN) ______ ► ______ OO

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC** (amount II **minus** amount OO) (if negative, enter "0") . . . . . . . . . . . . . . . . . ______ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP amounts. Enter this total amount on:

– line 220 for a corporation becoming a CCPC;
– line 230 for post-amalgamation; or
– line 240 for post-wind-up.

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**Schedule 55**

# Part III.1 Tax on Excessive Eligible Dividend Designations

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

**Do not use this area**

## Part 1 – Canadian-controlled private corporations and deposit insurance corporations

| | | | | |
|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | 35,000,000 | | |
| Total taxable dividends paid in the tax year | 100 | 35,000,000 | | |
| Total eligible dividends paid in the tax year | 150 | | | A |
| GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0") | 160 | | 561,479 | B |
| Excessive eligible dividend designation (line 150 **minus** line 160) | | | | C |
| **Deduct**: | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends * | 180 | | | D |
| Subtotal (amount C **minus** amount D) | | | | E |
| **Part III.1 tax on excessive eligible dividend designations – CCPC or DIC** (amount E **multiplied** by 20 %) | 190 | | | F |

Enter the amount from line 190 on line 710 of the T2 return.

## Part 2 – Other corporations

| | | | | |
|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | | | |
| Total taxable dividends paid in the tax year | 200 | | | |
| Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54) | | | | G |
| **Deduct**: | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends * | 280 | | | H |
| Subtotal (amount G **minus** amount H) | | | | I |
| **Part III.1 tax on excessive eligible dividend designations – Other corporations** (amount I **multiplied** by 20 %) | 290 | | | J |

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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**Schedule 500**

# Ontario Corporation Tax Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

## Part 1 – Ontario basic rate of tax for the year

**Ontario basic rate of tax for the year** . . . . . . . . . . . . . . . . . . . . . 11.5 % A

## Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . . . . . . . . . . . . . . . . . 3,293 B

**Ontario basic income tax**: amount B **multiplied** by Ontario basic rate of tax for the year (rate A from Part 1) . . . . . . . . . . . . . . 379 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

## Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

| | | |
|---|---|---|
| Income from active business carried on in Canada (amount from line 400 of the T2 return) | 3,293 | 1 |
| Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) | | 2 |
| Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) | | 3 |

**Ontario business limit reduction:**

Amount from line 3 ............ a

**Deduct:**

Amount from line E of the T2 return ______ x Number of days in the tax year after May 1, 2014 4 / Number of days in the tax year 4 = ______ b

Reduced Ontario business limit (amount a **minus** amount b) (if negative, enter "0") ______ ► ______ 4

Enter the least of amounts 1, 2, 3, and 4 ............ D

Ontario domestic factor (ODF): Ontario taxable income * / Taxable income earned in all provinces and territories ** = 3,293.00 / 3,293 = ...... 1.00000 E

Amount D × ODF (line E) ______ c

Ontario taxable income (amount B from Part 2) 3,293 d

Ontario small business income (lesser of amount c and amount d) ............ F

OSBD rate for the year ............ 7 % G

**Ontario small business deduction**: amount F **multiplied** by rate G ............ H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

## Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

**Ontario adjusted small business income** (lesser of amount D and amount d from Part 3) ............ I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

## Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

| | | |
|---|---|---|
| Amount D from Part 3 of Schedule 17 | | J |
| **Deduct:** | | |
| Ontario adjusted small business income (amount I from Part 4) | | K |
| Subtotal (amount J **minus** amount K) (if negative, enter "0") | | L |
| Amount L **multiplied** by rate G from Part 3 | | M |
| Ontario domestic factor (line E from Part 3) | 1.00000 | N |
| **Ontario credit union tax reduction** (amount M **multiplied** by ODF from line N) | | O |

Enter amount O on line 410 of Schedule 5.

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**Schedule 510**

# Ontario Corporate Minimum Tax

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Determination of CMT applicability

| | | |
|---|---|---|
| Total assets of the corporation at the end of the tax year * | 112 | 75,065,000 |
| Share of total assets from partnership(s) and joint venture(s) * | 114 | |
| Total assets of associated corporations (amount from line 450 on Schedule 511) | 116 | 10,000,000,000 |
| Total assets (total of lines 112 to 116) | | 10,075,065,000 |
| Total revenue of the corporation for the tax year ** | 142 | 62,962,500 |
| Share of total revenue from partnership(s) and joint venture(s) ** | 144 | |
| Total revenue of associated corporations (amount from line 550 on Schedule 511) | 146 | 5,000,000,000 |
| Total revenue (total of lines 142 to 146) | | 5,062,962,500 |

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

## Part 2 – Adjusted net income/loss for CMT purposes

| | | | | |
|---|---|---|---|---|
| Net income/loss per financial statements * | | | 210 | |
| **Add** (to the extent reflected in income/loss): | | | | |
| Provision for current income taxes/cost of current income taxes | 220 | | | |
| Provision for deferred income taxes (debits)/cost of future income taxes | 222 | | | |
| Equity losses from corporations | 224 | | | |
| Financial statement loss from partnerships and joint ventures | 226 | | | |
| Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act | 230 | | | |
| **Other additions** (see note below): | | | | |
| Share of adjusted net income of partnerships and joint ventures ** | 228 | | | |
| Total patronage dividends received, not already included in net income/loss | 232 | | | |
| 281 | 282 | | | |
| 283 | 284 | | | |
| Subtotal | | | | A |
| **Deduct** (to the extent reflected in income/loss): | | | | |
| Provision for recovery of current income taxes/benefit of current income taxes | 320 | | | |
| Provision for deferred income taxes (credits)/benefit of future income taxes | 322 | | | |
| Equity income from corporations | 324 | | | |
| Financial statement income from partnerships and joint ventures | 326 | | | |
| Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act | 330 | | | |
| Dividends not taxable under section 83 of the federal Act (from Schedule 3) | 332 | | | |
| Gain on donation of listed security or ecological gift | 340 | | | |
| Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act *** | 342 | | | |
| Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act **** | 344 | | | |
| Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act ***** | 346 | | | |
| Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act | 348 | | | |
| **Other deductions** (see note below): | | | | |
| Share of adjusted net loss of partnerships and joint ventures ** | 328 | | | |
| Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3 | 334 | | | |
| Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss | 336 | | | |
| Patronage dividends paid (from Schedule 16) not already included in net income/loss | 338 | | | |
| 381 | 382 | | | |
| 383 | 384 | | | |
| 385 | 386 | | | |
| 387 | 388 | | | |
| 389 | 390 | | | |
| Subtotal | | | | B |
| Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B) | | | 490 | |

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

**Note**

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

## Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

## Part 3 – CMT payable

| | | | |
|---|---|---|---|
| Adjusted net income for CMT purposes (line 490 in Part 2, if positive) | **515** | | |
| **Deduct:** | | | |
| CMT loss available (amount R from Part 7) | | | |
| **Minus:** Adjustment for an acquisition of control * | **518** | | |
| Adjusted CMT loss available | | | C |
| Net income subject to CMT calculation (if negative, enter "0") | **520** | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Amount from line 520 | | x | Number of days in the tax year before July 1, 2010 / Number of days in the tax year | / 4 | x 4 % = | 1 |
| Amount from line 520 | | x | Number of days in the tax year after June 30, 2010 / Number of days in the tax year | 4 / 4 | x 2.7 % = | 2 |
| | | | Subtotal (amount 1 **plus** amount 2) | | | 3 |

| | | | |
|---|---|---|---|
| Gross CMT: amount on line 3 above x OAF ** | **540** | | |
| **Deduct:** | | | |
| Foreign tax credit for CMT purposes *** | **550** | | |
| CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") | | | D |
| **Deduct:** | | | |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 379 | |
| Net CMT payable (if negative, enter "0") | | | E |

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = ______

**Ontario allocation factor** . . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

## Part 4 – Calculation of CMT credit carryforward

| | | | | | |
|---|---|---|---|---|---|
| CMT credit carryforward at the end of the previous tax year * | | | G | | |
| **Deduct:** | | | | | |
| CMT credit expired * | 00 | | | | |
| CMT credit carryforward at the beginning of the current tax year * (see note below) | | | 620 | | |
| **Add:** | | | | | |
| CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) | | | 650 | | |
| CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) | | | | | H |
| **Deduct:** | | | | | |
| CMT credit deducted in the current tax year (amount P from Part 5) | | | | | I |
| Subtotal (amount H **minus** amount I) | | | | | J |
| **Add:** | | | | | |
| Net CMT payable (amount E from Part 3) | | | | | |
| SAT payable (amount O from Part 6 of Schedule 512) | | | | | |
| Subtotal | | | | | K |
| CMT credit carryforward at the end of the tax year (amount J **plus** amount K) | | | 70 | | L |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

**Note:** If you entered an amount on line 620 or line 650, complete Part 6.

## Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

| | | | | | |
|---|---|---|---|---|---|
| CMT credit available for the tax year (amount H from Part 4) | | | | | M |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 379 | 1 | | |
| For a corporation that is not a life insurance corporation: | | | | | |
| CMT after foreign tax credit deduction (amount D from Part 3) | | 2 | | | |
| For a life insurance corporation: | | | | | |
| Gross CMT (line 540 from Part 3) | | 3 | | | |
| Gross SAT (line 460 from Part 6 of Schedule 512) | | 4 | | | |
| The **greater** of amounts 3 and 4 | | 5 | | | |
| **Deduct:** line 2 or line 5, whichever applies: | | | 6 | | |
| Subtotal (if negative, enter "0") | | 379 | | 379 | N |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 379 | | | |
| **Deduct:** | | | | | |
| Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) | | | | | |
| Subtotal (if negative, enter "0") | | 379 | | 379 | O |
| CMT credit deducted in the current tax year (least of amounts M, N, and O) | | | | | P |

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

## Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | CMT credit balance * |
|---|---|
| 10th previous tax year | 680 |
| 9th previous tax year | 681 |
| 8th previous tax year | 682 |
| 7th previous tax year | 683 |
| 6th previous tax year | 684 |
| 5th previous tax year | 685 |
| 4th previous tax year | 686 |
| 3rd previous tax year | 687 |
| 2nd previous tax year | 688 |
| 1st previous tax year | 689 |
| Total ** | |

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

## Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . . . . . . . . . . . . . . . . . . . . Q

**Deduct:**

CMT loss expired * . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . . . . . . . . . . . 720

**Add:**

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . . . . . . . . . . . . . . 750

CMT loss available (line 720 **plus** line 750) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . R

**Deduct:**

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . . . . . .

Subtotal (if negative, enter "0") S

**Add:**

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . . . . . . . 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . . . . . . . . . . . . . . . . . . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

**Note:** If you entered an amount on line 720 or line 750, complete Part 8.

## Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | Balance earned in a tax year ending before March 23, 2007 * | Balance earned in a tax year ending after March 22, 2007 ** |
|---|---|---|
| 10th previous tax year | 810 | 820 |
| 9th previous tax year | 811 | 821 |
| 8th previous tax year | 812 | 822 |
| 7th previous tax year | 813 | 823 |
| 6th previous tax year | 814 | 824 |
| 5th previous tax year | 815 | 825 |
| 4th previous tax year | 816 | 826 |
| 3rd previous tax year | 817 | 827 |
| 2nd previous tax year | 818 | 828 |
| 1st previous tax year | | 829 |
| Total *** | | |

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 511**

# ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-11-04 |

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 1 | HYDRO ONE LIMITED | 80512 9962 RC0001 | 0 | 0 |
| 2 | HYDRO ONE INC. | 86999 4731 RC0001 | 0 | 0 |
| 3 | 2486267 ONTARIO INC | 80232 6124 RC0001 | 0 | 0 |
| 4 | 2486268 ONTARIO INC | 80167 4078 RC0001 | 0 | 0 |
| 5 | HYDRO ONE NETWORKS INC. | 87086 5821 RC0001 | 10,000,000,000 | 5,000,000,000 |
| 6 | HYDRO ONE TELECOM INC. | 86800 1066 RC0001 | 0 | 0 |
| 7 | HYDRO ONE TELECOM LINK LIMITED | 88786 7513 RC0001 | 0 | 0 |
| 8 | MUNICIPAL BILLING SERVICES INC | 87560 6519 RC0001 | 0 | 0 |
| 9 | HYDRO ONE LAKE ERIE LINK MANAGEMENT INC | 87892 1519 RC0002 | 0 | 0 |
| 10 | 1938454 ONTARIO INC. | 86391 7795 RC0002 | 0 | 0 |
| 11 | 1943404 ONTARIO INC. | 86248 6123 RC0002 | 0 | 0 |
| 12 | B2M GP INC. | 81838 1840 RC0001 | 0 | 0 |
| 13 | HYDRO ONE B2M HOLDINGS INC | 82217 7531 RC0001 | 0 | 0 |
| 14 | HYDRO ONE B2M LP INC. | 81838 2046 RC0001 | 0 | 0 |
| 15 | NORFOLK ENERGY INC | 86289 0399 RC0001 | 0 | 0 |
| 16 | NORFOLK POWER DISTRIBUTION INC | 86289 2593 RC0001 | 0 | 0 |
| 17 | HALDIMAND COUNTY ENERGY INC | 89076 2412 RC0001 | 0 | 0 |
| 18 | HALDIMAND COUNTY HYDRO INC | 89075 9814 RC0001 | 0 | 0 |
| 19 | Woodstock Hydro Services Inc. | 89909 5012 RC0001 | 0 | 0 |
| 20 | 1937672 ONTARIO INC. | 81722 4561 RC0001 | 0 | 0 |
| 21 | 1937680 ONTARIO INC. | 81930 4924 RC0001 | 0 | 0 |
| 22 | 1937681 ONTARIO INC. | 81722 4363 RC0001 | 0 | 0 |
| 23 | Hydro One East-West Tie Inc. | 80105 5880 RC0001 | 0 | 0 |
| | | **Total** | 450 10,000,000,000 | 550 5,000,000,000 |

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511 Canada

Canada Revenue Agency / Agence du revenu du Canada

# T2 Corporation Income Tax Return

**200**

**055** **Do not use this area**

Filed: 2017-08-28
EB-2017-0051
Exhibit D2-09-01
Attachment 5
Page 1 of 124

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

## Identification

**Business number (BN)** . . . . . . . . . . **001** 87083 6269 RC0001

**Corporation's name**
**002** Hydro One Remote Communities Inc.

**Address of head office**
Has this address changed since the last time we were notified? . . . . . . . . . . . . **010** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
**011** 483 BAY STREET 8TH FLOOR
**012** SOUTH TOWER
City: **015** TORONTO
Province, territory, or state: **016** ON
Country (other than Canada): **017**
Postal code/Zip code: **018** M5G 2P5

**Mailing address** (if different from head office address)
Has this address changed since the last time we were notified? . . . . . . . . . . . **020** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
**021** c/o GIOVANNA BARAGETTI
**022** 483 BAY STREET 7TH FLOOR
**023** SOUTH TOWER
City: **025** TORONTO
Province, territory, or state: **026** ON
Country (other than Canada): **027**
Postal code/Zip code: **028** M5G 2P5

**Location of books and records** (if different from head office address)
Has the location of books and records changed since the last time we were notified? . . . . . . . . . . . . . . . . . . . . . **030** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
**031** 483 BAY STREET 7TH FLOOR
**032** SOUTH TOWER
City: **035** TORONTO
Province, territory, or state: **036** ON
Country (other than Canada): **037**
Postal code/Zip code: **038** M5G 2P5

**040** **Type of corporation at the end of the tax year**
1 [ ] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [X] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . . . . . . . . . . **043** 2015-11-05 (YYYY MM DD)

**To which tax year does this return apply?**
Tax year start **060** 2015-11-05 (YYYY MM DD)
Tax year-end **061** 2015-12-31 (YYYY MM DD)

**Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060?** . . **063** 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired . . . . . . . . . . . . . **065** ______ (YYYY MM DD)

**Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)?** . . . . . . . . . . . . **066** 1 Yes [ ] 2 No [X]

**Is the corporation a professional corporation that is a member of a partnership?** . . . . . . . . . . . . . . . . . **067** 1 Yes [ ] 2 No [X]

**Is this the first year of filing after:**
Incorporation? . . . . . . . . . . . . . . . **070** 1 Yes [ ] 2 No [X]
Amalgamation? . . . . . . . . . . . . . . . **071** 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . . **072** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . **076** 1 Yes [ ] 2 No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . **078** 1 Yes [ ] 2 No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . **079**

**Is the corporation a resident of Canada?**
**080** 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
**081**

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . **082** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**
**085**
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

**Do not use this area**

**095** **096** **898**

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| Is the corporation an associated CCPC? | 160 | | 23 |
| Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders who own voting shares? | 151 | | 19 |
| Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | X | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | X | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership account number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation own any shares in one or more foreign affiliates in the tax year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*? | 170 | | 29 |
| Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | X | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | |
| Does the corporation earn income from one or more Internet webpages or websites? | 180 | X | 88 |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine? | 202 | | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | | 3 |
| Is the corporation claiming any type of losses? | 204 | | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | X | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | | 6 |
| i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440? | 207 | | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any property that is eligible capital property? | 210 | X | 10 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)? | 213 | | 13 |
| Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits? | 221 | | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | X | 31 |
| Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | X | 33/34/35 |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | X | |
| Is the corporation claiming a surtax credit? | 237 | | 37 |
| Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II - Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit refund? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit refund? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments – continued from page 2

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates in the tax year? | 271 | | T1134 |
| Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | 262 | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | | X |
| Is the corporation inactive? | 280 | | X |

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

| Line | Product or service | Line | % |
|---|---|---|---|
| 284 | Electricity generation and distribution | 285 | 100.000 % |
| 286 | | 287 | % |
| 288 | | 289 | % |

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | | X |
| Did the corporation emigrate from Canada during the tax year? | 292 | | X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | | |

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

## Taxable income

| Description | Line | Amount | Amount | |
|---|---|---|---|---|
| Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. | 300 | | 203,578 | A |
| **Deduct:** Charitable donations from Schedule 2 | 311 | | | |
| Gifts to Canada, a province, or a territory from Schedule 2 | 312 | | | |
| Cultural gifts from Schedule 2 | 313 | | | |
| Ecological gifts from Schedule 2 | 314 | | | |
| Gifts of medicine from Schedule 2 | 315 | | | |
| Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | | | |
| Part VI.1 tax deduction* | 325 | | | |
| Non-capital losses of previous tax years from Schedule 4 | 331 | | | |
| Net capital losses of previous tax years from Schedule 4 | 332 | | | |
| Restricted farm losses of previous tax years from Schedule 4 | 333 | | | |
| Farm losses of previous tax years from Schedule 4 | 334 | | | |
| Limited partnership losses of previous tax years from Schedule 4 | 335 | | | |
| Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | |
| Prospector's and grubstaker's shares | 350 | | | |
| Subtotal | | | | B |
| Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | 203,578 | C |
| **Add:** Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | 355 | | | D |
| **Taxable income** (amount C **plus** amount D) | | | 203,578 | |
| Income exempt under paragraph 149(1)(t) | 370 | | | |
| **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | 203,578 | Z |
| **Taxable income** for the year from a personal services business** | | | | Z.1 |

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

** For a taxation year that ends after 2015.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

Income from active business carried on in Canada from Schedule 7 . . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . . ______ C.1

Corporation's business limit amount assigned to related CPCCs by virtue of the rules proposed in the March 22, 2016 Federal Budget (For more information, consult the Help (F1).) . . . . . ______ C.2

Business limit after assignment (amount C.1 **minus** amount C.2) . . . . . ______ **410** ______ C

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction:**

Amount C ______ x **415** *** ______ D / 11,250 = . . . . . ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** ______ F

**Small business deduction**

Amount A, B, C, or F, whichever is the least ______ x Number of days in the tax year before January 1, 2016 (57) / Number of days in the tax year (57) x 17 % = ______ 1

Amount A, B, C, or F, whichever is the least ______ x Number of days in the tax year after December 31, 2015, and before January 1, 2017 (______) / Number of days in the tax year (57) x 17.5 % = ______ 2

Total of amounts 1 and 2 (enter amount G on line I on page 7) **430** ______ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | A |
| Lesser of amounts B9 and H9 from Part 9 of Schedule 27 | | B | | |
| Amount K13 from Part 13 of Schedule 27 | | C | | |
| Personal service business income | 432 | D | | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | E | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | F | | |
| Aggregate investment income from line 440 on page 6* | | G | | |
| Subtotal (**add** amounts B to G) | | | | H |
| Amount A **minus** amount H (if negative, enter "0") | | | | I |
| **General tax reduction for Canadian-controlled private corporations** – Amount I **multiplied** by 13 % | | | | J |

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | 203,578 | K |
| Lesser of amounts B9 and H9 from Part 9 of Schedule 27 | | L | | |
| Amount K13 from Part 13 of Schedule 27 | | M | | |
| Personal service business income | 434 | N | | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | O | | |
| Subtotal (**add** amounts L to O) | | | | P |
| Amount K **minus** amount P (if negative, enter "0") | | | 203,578 | Q |
| **General tax reduction** – Amount Q **multiplied** by 13 % | | | 26,465 | R |

Enter amount R on line 639 on page 7.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

Aggregate investment income from Schedule 7 . . . . . . . . **440** ______ x ( 26 2 / 3 + 4 x ( Number of days in the tax year after 2015 ______ / Number of days in the tax year 57 ) % = ______ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . . . . . . . . . . . . . . . . . . ______ B

**Deduct:**
Foreign investment income from Schedule 7 . . . . . **445** ______ x ( 9 1 / 3 – 1 1 / 3 x ( Number of days in the tax year after 2015 ______ / Number of days in the tax year 57 ) % = ______ C

(if negative, enter "0") ______ ______ D

Amount A **minus** amount D (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ E

Taxable income from line 360 on page 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ F

**Deduct:**
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ G

Foreign non-business income tax credit from line 632 on page 7 . . . . ______ x 100 / 35 = ______ H

Foreign business income tax credit from line 636 on page 7 . . . . . . . . . . . . . ______ x 4 = ______ I

Subtotal ______ ______ J

______ K

K x ( 26 2 / 3 + 4 x Number of days in the tax year after 2015 ______ / Number of days in the tax year 57 ) % = ______ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . . . . . . . . . . . . . . . . . . . ______ M

**Refundable portion of Part I tax** – Amount E, L, or M, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . **450** ______ N

## Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . . . . . . . . . . . . . . **460** ______

**Deduct:** Dividend refund for the previous tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **465** ______

______ ______ O

**Add** the total of:

Refundable portion of Part I tax from line 450 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ P

Total Part IV tax payable from Schedule 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . . . . . . . . . . . . . . . . . . . . . **480** ______

______ ______ R

**Refundable dividend tax on hand at the end of the tax year** – Amount O **plus** amount R . . . . . . . . . . . . . . . . . . . . . **485** ______

## Dividend refund

**Private and subject corporations at the time taxable dividends were paid in the tax year**

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . . . . . . . . . . . . . . . . . . ______ x [ ( 1 / 3 ) + ( 5 x ( Number of days in the tax year after 2015 ______ / Number of days in the tax year 57 ) % ] = ______ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ T

**Dividend refund** – Amount S or T, whichever is less . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ U

Enter amount U on line 784 on page 8.

## Part I tax

| | | | | |
|---|---|---|---|---|
| Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %* | 550 | | 77,360 | A |

* If an amount of taxable income for the year from a personal services business has been entered on line Z.1, the result of the following calculation will be added to the amount on line 550:

Amount Z.1 ______ x (Number of days in the taxation year that are after 2015 / Number of days in the taxation year 57) x 5 % = ______ A.1

| | | | | |
|---|---|---|---|---|
| Recapture of investment tax credit from Schedule 31 | 602 | | | B |

**Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income**
(if it was a CCPC throughout the tax year)

| | | | |
|---|---|---|---|
| Aggregate investment income from line 440 on page 6 | | | C |
| Taxable income from line 360 on page 3 | | D | |
| **Deduct:** | | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | E | |
| Net amount (amount D **minus** amount E) | | | F |

**Refundable tax on CCPC's investment income** –

( 6 2 / 3 + 4 x (Number of days in the tax year after 2015 ______ / Number of days in the tax year 57) ) % of whichever is less: amount C or amount F ... 604 ______ G

| | | | |
|---|---|---|---|
| Subtotal (**add** amounts A, B, and G) | | 77,360 | H |

**Deduct:**

| | | | | | |
|---|---|---|---|---|---|
| Small business deduction from line 430 on page 4 | | | I | | |
| Federal tax abatement | 608 | 20,358 | | | |
| Manufacturing and processing profits deduction from Schedule 27 | 616 | | | | |
| Investment corporation deduction | 620 | | | | |
| Taxed capital gains 624 | | | | | |
| Additional deduction – credit unions from Schedule 17 | 628 | | | | |
| Federal foreign non-business income tax credit from Schedule 21 | 632 | | | | |
| Federal foreign business income tax credit from Schedule 21 | 636 | | | | |
| General tax reduction for CCPCs from amount J on page 5 | 638 | | | | |
| General tax reduction from amount R on page 5 | 639 | 26,465 | | | |
| Federal logging tax credit from Schedule 21 | 640 | | | | |
| Eligible Canadian bank deduction under section 125.21 | 641 | | | | |
| Federal qualifying environmental trust tax credit | 648 | | | | |
| Investment tax credit from Schedule 31 | 652 | 170 | | | |
| Subtotal | | 46,993 | | 46,993 | J |

| | | |
|---|---|---|
| **Part I tax payable** – Amount H **minus** amount J | 30,367 | K |

Enter amount K on line 700 on page 8.

## Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **http://www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, personal information bank CRA PPU 047.

## Summary of tax and credits

**Federal tax**

| | Code | Amount |
|---|---|---|
| Part I tax payable from amount K on page 7 | 700 | 30,367 |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | 30,367 |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | Code | Amount | |
|---|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | 15,727 | |
| Total tax payable | 770 | 46,094 | A |

**Deduct other credits:**

| | Code | Amount | |
|---|---|---|---|
| Investment tax credit refund from Schedule 31 | 780 | | |
| Dividend refund from amount U on page 6 | 784 | | |
| Federal capital gains refund from Schedule 18 | 788 | | |
| Federal qualifying environmental trust tax credit refund | 792 | | |
| Canadian film or video production tax credit refund (Form T1131) | 796 | | |
| Film or video production services tax credit refund (Form T1177) | 797 | | |
| Tax withheld at source | 800 | | |
| Total payments on which tax has been withheld | 801 | | |
| Provincial and territorial capital gains refund from Schedule 18 | 808 | | |
| Provincial and territorial refundable tax credits from Schedule 5 | 812 | | |
| Tax instalments paid | 840 | 60,000 | |
| Total credits | 890 | 60,000 | 60,000 B |

Refund code 894 1 Overpayment 13,906

Balance (amount A **minus** amount B) -13,906

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . .

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

## Certification

I, 950 BARAGETTI (Last name (print)) 951 GIOVANNA (First name (print)) 954 Vice President, Corporate Tax (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2016-06-21 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (416) 345-6778 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No X

958 GLENDY CHEUNG Name (print) 959 (416) 345-6812 Telephone number

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

# Schedule of Instalment Remittances

Name of corporation contact: Brian Soares
Telephone number: (416) 345-6728

| Effective interest date | Description (instalment remittance, split payment, assessed credit) | Amount of credit |
|---|---|---|
| 2015-12-31 | Instalments | 60,000 |
| | Instalments | |
| | Instalments | |
| | Instalments | |
| | Instalments | |
| | Instalments | |
| | Instalments | |
| | Instalments | |
| | Instalments | |
| | Instalments | |
| | Instalments | |
| | Instalments/transfer | |
| | | |

**Total amount of instalments claimed (carry the result to line 840 of the T2 Return)** 60,000 **A**

**Total instalments credited to the taxation year per T9** 60,000 **B**

## Transfer

| | Account number | Taxation year end | Amount | Effective interest date | Description |
|---|---|---|---|---|---|
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 100**

Form identifier 100

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

## Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 9,110,000 | 12,280,000 |
| | Total tangible capital assets | 2008 | + | 68,463,000 | 68,581,000 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 25,793,000 | 26,032,000 |
| | Total intangible capital assets | 2178 | + | | |
| | Total accumulated amortization of intangible capital assets | 2179 | – | | |
| | Total long-term assets | 2589 | + | 19,766,000 | 20,236,000 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 71,546,000 | 75,065,000 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 12,111,000 | 15,430,000 |
| | Total long-term liabilities | 3450 | + | 59,890,000 | 60,179,000 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 72,001,000 | 75,609,000 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | -455,000 | -544,000 |
| | **Total liabilities and shareholder equity** | 3640 | = | 71,546,000 | 75,065,000 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | -4,913,000 | -5,000,000 |

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | Ontario Hydro Remote Communities Service Company Inc. |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Income statement information** | | | | |
| | Total sales of goods and services | 8089 | + | 7,646,000 | 690,000 |
| | Cost of sales | 8518 | – | 4,265,000 | 271,000 |
| | **Gross profit/loss** | 8519 | = | 3,381,000 | 419,000 |
| | Cost of sales | 8518 | + | 4,265,000 | 271,000 |
| | Total operating expenses | 9367 | + | 2,911,000 | 419,000 |
| | **Total expenses** (mandatory field) | 9368 | = | 7,176,000 | 690,000 |
| | Total revenue (mandatory field) | 8299 | + | 7,646,000 | 690,000 |
| | Total expenses (mandatory field) | 9368 | – | 7,176,000 | 690,000 |
| | **Net non-farming income** | 9369 | = | 470,000 | |
| | **Farming income statement information** | | | | |
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | 470,000 | |
| | **Total other comprehensive income** | 9998 | = | 2,000 | |
| | **Extraordinary items and income (linked to Schedule 140)** | | | | |
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | 383,000 | |
| | Future (deferred) income tax provision | 9995 | – | | |
| | Total – Other comprehensive income | 9998 | + | 2,000 | |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 89,000 | |

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 141**

# Notes Checklist

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . **095** 1 Yes X 2 No

Is the accountant connected* with the corporation? . . . **097** 1 Yes X 2 No

**Note**

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . 1 ☐

Completed a review engagement report . . . 2 ☐

Conducted a compilation engagement . . . 3 ☐

## Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . **099** 1 Yes ☐ 2 No ☐

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: . . . **110**

Prepared the tax return (financial statements prepared by client) . . . 1 ☐

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . 2 ☐

Were notes to the financial statements prepared? . . . **101** 1 Yes X 2 No

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . **104** 1 Yes X 2 No

Is re-evaluation of asset information mentioned in the notes? . . . **105** 1 Yes X 2 No

Is contingent liability information mentioned in the notes? . . . **106** 1 Yes X 2 No

Is information regarding commitments mentioned in the notes? . . . **107** 1 Yes X 2 No

Does the corporation have investments in joint venture(s) or partnership(s)? . . . **108** 1 Yes 2 No X

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income Increase (decrease) | | In OCI Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . **250** 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . **255** 1 Yes [X] 2 No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . . **260** 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

# T2 BAR CODE RETURN

**Name: Hydro One Remote Communities Inc.**

**BN: 87083 6269 RC 0001**

**Tax Year Start: 2015-11-05**

**Tax Year End: 2015-12-31**

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and was wholly owned by the Province of Ontario (the Province) until October 31, 2015. On October 31, 2015, Hydro One Limited, a wholly owned subsidiary of the Province, acquired all issued and outstanding shares of Hydro One from the Province. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the Business Corporations Act (Ontario) and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. These Financial Statements have been prepared for the purpose of filing the Company's income tax return, as on November 5, 2015, the common shares of Hydro One Limited began trading on the Toronto Stock Exchange, and as a result, the Company lost its status as a Canadian-

Controlled Private Corporation. As these Financial Statements have not been prepared for general purposes, some users may require additional information. These Financial Statements present the financial position of the Company at December 31, 2015 and the results of its operations and its cash flows for the period from November 5, 2015 to December 31, 2015. The comparative information is presented as at November 4, 2015 and for the period from November 1, 2015 to November 4, 2015.

The Company uses a cost recovery model applied to achieve breakeven net income. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. For the current period, the Company has reported net income due to recognition of tax recovery resulting from the Company no longer being exempt from tax under the Federal Tax Regime. This tax is not recovered from ratepayers as it is funded by the Company's shareholder, and therefore, it is not included in the cost recovery model applied to achieve breakeven net income. See Note 6 - Income Taxes.

Hydro One Remote Communities performed an evaluation of subsequent events through to March 15, 2016, 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 20 - Subsequent Event.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairment, contingencies, unbilled revenue, allowance for doubtful accounts 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.

Rate Setting

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

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

Revenue Recognition

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

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are 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.

Long-term accounts receivable are recorded at their invoiced amount and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. Provision for uncollectible amounts for this component is set at the inception of the balance and is maintained until settlement of those amounts. The provision for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

Income Taxes

On October 31, 2015, the Company ceased to be exempt from tax under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) (Federal Tax Regime). Prior to that date, Hydro One Remote Communities was required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the Electricity Act, 1998 (Ontario) (PILs Regime). These payments were 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. Upon exiting the PILs Regime, Hydro One Remote Communities 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 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 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 Statements of Operations and Comprehensive Income (Loss).

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.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter -company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash 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%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. 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 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

Generation

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

Distribution

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

Administration and Service

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

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 (Loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction in Progress

Construction 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

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 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 |
| Generation | 20 years | 3% - 7% | 5% |

| | | | |
|---|---|---|---|
| Distribution | 45 years | 1% - 7% | 2% |
| Administration and service | 36 years | 3% - 20% | 4% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 assets where no asset retirement obligation 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 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.

The carrying costs of most of Hydro One Remote Communities' 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. As at December 31, 2015, no asset impairment had been recorded.

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 Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income (Loss). 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents OCI and net income in a single continuous Statement of Operations and Comprehensive Income (Loss).

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.

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 11 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2015. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's 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 plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets 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. The measurement date for all plans is December 31.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit 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, 2015.

Post-retirement and post-employment benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of the these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro

One's 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 accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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.

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, 2015.

Stock-Based Compensation

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited 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.

Loss Contingencies

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

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

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement 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 Remote Communities records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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 Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

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 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 2015-05, 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 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 financial statements.

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 Balance Sheets.

4. DEPRECIATION AND AMORTIZATION

| (thousands of Canadian dollars) | Period from November 5 to December 31, 2015 |
|---|---|
| Depreciation of property, plant and equipment | 428 |
| Asset removal costs | 120 |
| Amortization of regulatory assets | 353 |
| | 901 |

5. FINANCING CHARGES

| (thousands of Canadian dollars) | Period from November 5 to December 31, 2015 |
| --- | --- |
| Interest on long-term debt | 246 |
| Interest on inter-company demand facility | 13 |
| Amortization of hedging losses | 2 |
| Other | 5 |
| Less: Interest capitalized on construction in progress | (11) |
| | 255 |

6. 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:

(thousands of Canadian dollars) Period from November 5 to December

31, 2015

Income taxes / provision for PILs at statutory rate 124

Increase (decrease) resulting from:

Net temporary differences included in amounts charged to customers:

RRPR variance account 1,514

Environmental expenditures (65)

Overheads capitalized for accounting but deducted for tax purposes

(47)

Pension contribution in excess of pension expense (30)

Interest capitalized for accounting but deducted for tax purposes

54

Losses carryforward (2,210)

Depreciation and amortization in excess of capital cost allowance

1,005

Post-retirement and post-employment benefit expense in excess of cash

payments 136

Other 72

Net temporary differences 429

Prior year adjustments (161)

Other permanent differences (9)

Total income taxes / provision for PILs 383

Current income taxes / provision for PILs 383

Deferred income taxes / provision for PILs -

Total income taxes / provision for PILs 383

Effective income tax rate 81.5%

The provision for PILs / current income taxes is remitted to, or received from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime), respectively. At December 31, 2015, the Company had $327 thousand receivable from the OEFC, and $37 thousand payable to the CRA.

Departure Tax

On October 31, 2015, the Company's exemption from tax under the Federal Tax Regime ceased to apply. Under the PILs Regime, the Company 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 Remote Communities making payments in lieu of tax (Departure Tax) totalling $5,000 thousand. To enable Hydro One Remote Communities to make the Departure Tax payment, Hydro One subscribed for 64 common shares of Hydro One Remote Communities for $5,000 thousand. The Company used the proceeds of this share subscription to pay the Departure Tax.

For the period ended December 31, 2015, Hydro One Remote Communities' income taxes include income tax recovery of $87 thousand relating to the partial utilization of the deferred tax asset generated upon the transition from the PILs Regime to the Federal Tax Regime. The following table presents a reconciliation of net income to net income under the cost recovery model to achieve breakeven net income:

(thousands of Canadian dollars) Period from November 5 to December 31, 2015

Net income before income taxes 470

Income taxes under cost-recovery model 470

Net income under cost-recovery model -

Tax recovery (87)

Net income 87

Deferred Income Tax Assets

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, 2015, deferred income tax assets and liabilities consisted of the following:

(thousands of Canadian dollars) December 31, 2015

Deferred income tax assets

Post-retirement and post-employment benefits expense in excess of cash payments

5,038

Environmental expenditures 3,984

Depreciation and amortization in excess of capital cost allowance

926

Regulatory amounts not recognized for tax 1,845 2,263

(5,803)

Other (215)

Total deferred income tax assets 3,930

Less: current portion 125

3,805

During the period ended December 31, 2015, there was no change in the rate applicable to future taxes. The Company has recorded a valuation allowance in the amount of $6,622 thousand in respect of capital property.

7. ACCOUNTS RECEIVABLE

December 31, 2015 (thousands of Canadian dollars) Current accounts receivable Long-term accounts receivable

Total

Accounts receivable - billed 3,514 1,181 4,695

Accounts receivable - unbilled 1,077 - 1,077

Accounts receivable, gross 4,591 1,181 5,772

Allowance for doubtful accounts (156) (111) (267)

Accounts receivable, net 4,435 1,070 5,505

The following table shows the movements in the total allowance for doubtful accounts for the period ended December 31, 2015:

(thousands of Canadian dollars) Period from November 5 to December 31, 2015

Allowance for doubtful accounts - beginning of period (240)

Write-offs 1

Adjustments to allowance for doubtful accounts (28)

Allowance for doubtful accounts - end of period (267)

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2015 (thousands of Canadian dollars) Property, Plant and

Equipment Accumulated Depreciation Construction

in Progress

Total

Generation 45,779 21,150 2,966 20,330

826 20,330

25,455 20,330

Distribution 9,780 2,049 312 8,043

Administration and Service 11,716 2,594 50 9,172

67,275 25,793 1,188 42,670

Financing charges capitalized on property, plant and equipment under construction were $11 thousand for the period ended December 31 2015.

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

(thousands of Canadian dollars) December 31, 2015

Regulatory assets:

Environmental 11,051

RRPR variance account

03

2,760

Post-retirement and post-employment benefits 2,285

Share-based compensation 99

Total regulatory assets 16,195

Less: current portion 1,483

14,712

Regulatory liabilities:

Deferred income tax regulatory liability 3,930

Total regulatory liabilities 3,930

Less: current portion 125

3,805

Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recovered in future rates, the Company has recorded an equivalent amount as a regulatory asset. During the period ended December 31, 2015, the environmental regulatory asset decreased by $448 thousand to reflect related changes in the Company's environmental liabilities. 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 Company's actual environmental expenditures. In the absence of rate-regulated accounting, during the period ended December 31, 2015, operation, maintenance and administration expenses would have been lower by $448 thousand. In addition, amortization expense would have been lower by $366 and financing charges would have been higher by $53 thousand.

RRPR Variance Account

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2015, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of cumulative RRRP amounts received. During the period ended December 31, 2015, RRRP amounts received were higher than amounts required to achieve breakeven net income, and as such, the regulatory asset was reduced by $103 thousand. In the absence of rate-regulated accounting, revenue for the period ended December 31, 2015 would have been higher by $103 thousand.

Post-Retirement and Post-Employment Benefits

The Company 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, 2015 OCI would have been higher by $352 thousand.

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 Hydro One Limited share price and recognized using the graded-vesting attribution method. In the absence of rate-regulated accounting, during the period ended December 31, 2015 operation, maintenance and administration expenses would have been higher by $69 thousand.

Deferred Income Tax Regulatory 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 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 income tax expense for the period ended December 31, 2015 would have been lower by approximately $429 thousand.

10. LONG-TERM DEBT

Long-term debt totalling $33,000 thousand is payable to Hydro One and consists of a $23,000 thousand note maturing in 2036 and a $10,000 thousand note maturing in 2044.

The $23,000 thousand note was issued on May 19, 2005, with an interest rate of 5.38% per annum and a maturity date of May 20, 2036. On issuance of this note, $115 thousand of transaction costs and a $31 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

The $10,000 thousand note was issued on June 6, 2014, with an interest rate of 4.19% per annum and a maturity date of June 6, 2044. On issuance of this note, $50 thousand of transaction costs and a $10 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

## 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.

Hydro One Remote Communities 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 Remote Communities 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, 2015, the Company's 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 Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2015 are as follows:

December 31, 2015 (thousands of Canadian dollars) Carrying

Value Fair

Value

Level 1

Level 2

Level 3

Liabilities:

Inter-company demand facility 6,056 6,056 6,056 - -

Long-term debt 33,000 37,957 - 37,957 -

39,056 44,013 6,056 37,957 -

The fair value 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 period ended December 31, 2015.

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 foreign exchange risk is currently not significant, although Hydro One could in the future decide to issue and allocate foreign currency-denominated debt to the Company, along with an allocation of the resulting foreign exchange gains and losses. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2015, 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 Remote Communities did not earn a significant amount of revenue from any individual customer. At December 31, 2015, there was no significant accounts receivable balance due from any single customer.

At December 31, 2015, the Company's total provision for bad debts was $267 thousand. Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2015, approximately 44% of the Company's current accounts receivable were aged more than 60 days. Sufficient allowances have been recorded to reflect the risk of potential credit losses.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities 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, 2015, accounts payable and accrued liabilities in the amount of $5,721 thousand are expected to be settled in cash at their carrying amounts within the next 12 months.

# T2 BAR CODE RETURN

**Name: Hydro One Remote Communities Inc.**

**BN: 87083 6269 RC 0001**

**Tax Year Start: 2015-11-05**

**Tax Year End: 2015-12-31**

At December 31, 2015, Hydro One Remote Communities had long-term debt in the principal amount of $33,000 thousand. Principal repayments and weighted average interest rates are summarized by the number of years to maturity in the following table.

Long-term Debt

Principal Repayments Weighted Average

Interest Rate

Years to Maturity (thousands of Canadian dollars) (%)

1 year - 5.0

2 years - 5.0

3 years - 5.0

4 years - 5.0

5 years - 5.0

- 5.0

6 - 10 years - 5.0

Over 10 years 33,000 5.0

33,000 5.0

Interest payments on long-term debt are summarized by year in the following table:

Interest Payments

Year (thousands of Canadian dollars)

2016 1,656

2017 1,656

2018 1,656

2019 1,656

| | |
|---|---|
| 2020 | 1,656 |
| | 8,280 |
| 2021-2025 | 8,282 |
| 2026 + | 20,744 |
| | 37,306 |

12. 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 most regular employees of Hydro One and its subsidiaries. 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 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.

Company 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 during the period ended December 31, 2015 of $28 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.

At December 31, 2015, based on the December 31, 2013 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,683 million. The fair value of pension plan assets available for these benefits was $6,731 million.

Post-Retirement and Post-Employment Benefits

During the period ended December 31, 2015, Hydro One Remote Communities charged $112 thousand of post-retirement and post-employment benefit costs to results of operations, and capitalized $61 thousand as part of the cost of property, plant and equipment. Benefits paid by the Company were $13 thousand. In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $352 thousand was recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

(thousands of Canadian dollars) December 31, 2015

Accrued liabilities 373

Post-retirement and post-employment benefit liability 13,517

13,890

13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2015:

(thousands of Canadian dollars) Period from November 5 to

December 31, 2015

Environmental liabilities, beginning of period 11,812

Interest accretion 53

Expenditures (366)

Revaluation adjustment (448)

Environmental liabilities, end of period 11,051

Less: current portion 1,483

9,568

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheets after factoring in the discount rate:

| (thousands of Canadian dollars) | December 31, 2015 |
|---|---|
| Undiscounted environmental liabilities | 11,474 |
| Less: discounting accumulated liabilities to present value | 423 |
| Discounted environmental liabilities | 11,051 |

At December 31, 2015, the estimated future environmental expenditures were as follows:

| (thousands of Canadian dollars) | |
|---|---|
| 2016 | 1,483 |
| 2017 | 1,960 |
| 2018 | 1,891 |
| 2019 | 2,429 |
| 2020 | 3,711 |
| | 11,474 |

The Company records a liability for the estimated future expenditures for the contaminated LAR 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 a rate of 3.6%. 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.

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $11,474 thousand. These expenditures are expected to be incurred over the period from 2016 to 2020. As a result of its annual review of environmental liabilities, during the period ended December 31, 2015, the Company recorded a revaluation adjustment to decrease the LAR environmental liability by $448 thousand.

14. SHARE CAPITAL

Common Shares

The Company has 267 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

The following table presents the movement in common shares during the year ended December 31, 2015.

(number of common shares)

| | |
|---|---|
| Number of common shares - January 1, 2015 | 2 |
| Share split (a) | 200 |
| Common shares issued (b) | 64 |
| Common shares issued (c) | 1 |
| Number of common shares - December 31, 2015 | 267 |

(a) On November 2, 2015, all of the issued and outstanding common shares of Hydro Once Remote Communities were changed into 202 issued and outstanding common shares of the Company.

(b) On November 4, 2015, Hydro One Remote Communities issued 64 common shares to Hydro One for proceeds of $5 million.

(c) On November 3, 2015, Hydro One Remote Communities declared a stock dividend on its common shares, which due to the number of shares issued and the resulting effect on the price per share was treated as a stock split. On November 5, 2015, Hydro One Remote Communities effected a reverse split and issued as consideration one common share to Hydro One. There was no impact to the capital structure of Hydro One Remote Communities as a net result of the stock dividend and the reverse split.

Dividends

The Company does not pay dividends under its breakeven business model.

15. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Remote communities, in current and future periods.

Share Grant Plans

At December 31, 2015, Hydro One Limited 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). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. During the period ended December 31, 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees of Hydro One Remote Communities.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. During the period ended December 31, 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The fair value of the Hydro One Limited share grants is estimated based on the grant date Hydro One Limited 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 to employees of Hydro One Remote Communities during the period ended December 31, 2015 is $1,091 thousand. Total share based compensation recognized during the period ended December 31, 2015 by Hydro One Remote Communities was $99 thousand 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 the period ended December 31, 2015. The Company will reevaluate this assumption in subsequent periods based on actual experience.

A summary of Hydro One Remote Communities' share grant activity under the Share Grant Plans as of December 31, 2015 is presented below:

| Period from November 5 to December 31, 2015 | Share Grants (Number) | Weighted-Average Price |
|---|---|---|
| Outstanding - beginning of period | - | - |
| Granted (non-vested) | 53,196 | $20.50 |
| Outstanding - end of period | 53,196 | - |

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One Limited 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 Limited. 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 Limited adopted a Long-term Incentive Plan (LTIP). Under the LTIP, long-term incentives will be granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited 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 of Hydro One Limited.

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.

16. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited, and the Province is the majority shareholder of Hydro One Limited. The OEFC and IESO are related parties to Hydro One Remote

Communities because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One Remote Communities are described below.

IESO

" Hydro One Remote Communities receives amounts for RRRP from the IESO. RRRP amounts received for the period ended December 31, 2015 were $5,376 thousand. Consistent with its breakeven business model, the Company recognized $5,273 thousand as RRRP revenue for the period ended December 31, 2015, with the difference recorded in the RRPR variance account.

OEFC

" During the period ended December 31, 2015, Hydro One Remote Communities made a Departure Tax payment to the OEFC totaling $5 million.

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

| (thousands of Canadian dollars) | December 31, 2015 |
|---|---|
| Accounts receivable | 95 |
| Income tax receivable | 327 |

Transactions with 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.

Hydro One and Subsidiaries

# T2 BAR CODE RETURN

**Name: Hydro One Remote Communities Inc.**

**BN: 87083 6269 RC 0001**

**Tax Year Start: 2015-11-05**

**Tax Year End: 2015-12-31**

" The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its other 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 corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. Revenues for the period ended December 31, 2015 $68 thousand related to the provision of services to Hydro One and its other subsidiaries. Operation, maintenance and administration costs for the period ended December 31, 2015 include $448 thousand related to the purchase of services from Hydro One and its other subsidiaries.

" The Company's long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One and its other subsidiaries. Financing charges for the period ended December 31, 2015 include interest expense on the long-term debt of $246 thousand, and interest expense on the inter-company demand facility of $13 thousand. At December 31, 2015, the Company had accrued interest payable to Hydro One totaling $172 thousand.

" In 2015, Hydro One Limited established certain stock-based compensation plans, however they represent components of costs of Hydro One and its subsidiaries, including Hydro One Remote Communities in current and future periods. Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with the share grant plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans. At December 31, 2015, Hydro One Remote Communities had a payable of $99 thousand to Hydro One associated with these plans. See Note 15 - Stock-based Compensation.

17. STATEMENTS OF CASH FLOWS

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

(thousands of Canadian dollars) Period from November 5 to December 31, 2015

Accounts receivable (601)

Fuel, materials and supplies 303

Income taxes receivable 2,329

Long-term accounts receivable 16

Accounts payable (548)

Accrued liabilities (566)

Accrued interest (580)

Income taxes payable 37

Post-retirement and post-employment benefit liability 33

423

Supplementary information:

Net interest paid 827

Taxes paid 5,000

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid are fully recovered.

18. CONTINGENCIES

Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

In September 2015, Hydro One and three of its subsidiaries, including Hydro One Remote Communities, 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 Hydro One 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, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One 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 Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

19. COMMITMENTS

Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years.

During the period ended December 31, 2015, the Company made lease payments totalling $nil. At December 31, 2015, the future minimum lease payments under non-cancellable operating leases were as follows: 2016 - $120 thousand; 2017 - $120 thousand; 2018 - $150 thousand; 2019 - $150 thousand; 2020 - $150 thousand; and thereafter - $300 thousand.

20. SUBSEQUENT EVENT

Long-term Debt

On February 24, 2016, Hydro One Remote Communities issued a $10,000 thousand note with a maturity date of February 24, 2026 and a coupon rate of 2.79%. The note is payable to Hydro One Inc.

**SCHEDULE 100**

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

### Assets – lines 1000 to 2599

| | | | | | |
|---|---|---|---|---|---|
| 1062 | 4,435,000 | 1066 | 327,000 | 1122 | 2,740,000 |
| 1480 | 1,483,000 | 1481 | 125,000 | 1599 | 9,110,000 |
| 1740 | 55,559,000 | 1741 | -23,199,000 | 1900 | 11,716,000 |
| 1901 | -2,594,000 | 1920 | 1,188,000 | 2008 | 68,463,000 |
| 2009 | -25,793,000 | 2420 | 15,961,000 | 2421 | 3,805,000 |
| 2589 | 19,766,000 | 2599 | 71,546,000 | | |

### Liabilities – lines 2600 to 3499

| | | | | | |
|---|---|---|---|---|---|
| 2620 | 5,721,000 | 2629 | 172,000 | 2680 | 37,000 |
| 2860 | 6,056,000 | 2960 | 125,000 | 3139 | 12,111,000 |
| 3140 | 33,000,000 | 3320 | 13,517,000 | 3321 | 13,373,000 |
| 3450 | 59,890,000 | 3499 | 72,001,000 | | |

### Shareholder equity – lines 3500 to 3640

| | | | | | |
|---|---|---|---|---|---|
| 3500 | 5,000,000 | 3580 | -542,000 | 3600 | -4,913,000 |
| 3620 | -455,000 | 3640 | 71,546,000 | | |

### Retained earnings – lines 3660 to 3849

| | | | | | |
|---|---|---|---|---|---|
| 3660 | -5,000,000 | 3680 | 87,000 | 3849 | -4,913,000 |

**SCHEDULE 125**

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

## Description

Operating name . . . . . . . . **0001** Ontario Hydro Remote Communities Service Company Inc.

Sequence number . . . . . . . **0003** 01

## Other comprehensive income – lines 7000 to 7020

| | |
|---|---|
| 7008 | 2,000 |

## Revenue – lines 8000 to 8299

| | | | | | |
|---|---|---|---|---|---|
| 8000 | 7,646,000 | 8089 | 7,646,000 | 8299 | 7,646,000 |

## Cost of sales – lines 8300 to 8519

| | | | | | |
|---|---|---|---|---|---|
| 8408 | 4,265,000 | 8518 | 4,265,000 | 8519 | 3,381,000 |

## Operating expenses – lines 8520 to 9369

| | | | | | |
|---|---|---|---|---|---|
| 8670 | 901,000 | 8714 | 255,000 | 9270 | 1,755,000 |
| 9367 | 2,911,000 | 9368 | 7,176,000 | 9369 | 470,000 |

## Extraordinary items and taxes – lines 9970 to 9999

| | | | | | |
|---|---|---|---|---|---|
| 9970 | 470,000 | 9990 | 383,000 | 9998 | 2,000 |
| 9999 | 89,000 | | | | |

Canada Revenue Agency / Agence du revenu du Canada

# Net Income (Loss) for Income Tax Purposes

**Schedule 1**

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

| | | | | | |
|---|---|---|---|---|---|
| Amount calculated on line 9999 from Schedule 125 | | | | 89,000 | A |
| **Add:** | | | | | |
| Provision for income taxes – current | | 101 | 383,000 | | |
| Amortization of tangible assets | | 104 | 901,000 | | |
| Non-deductible meals and entertainment expenses | | 121 | 3,586 | | |
| Reserves from financial statements – balance at the end of the year | | 126 | 22,181,378 | | |
| Subtotal of additions | | | 23,468,964 | 23,468,964 | |
| **Other additions:** | | | | | |
| Debt issue expense | | 208 | 2,963 | | |
| **Miscellaneous other additions:** | | | | | |
| 600 Computer software expenses | | 290 | 1,287 | | |
| 601 OPEB US GAAP Valuation | | 291 | 351,492 | | |
| 602 Opening OPEB Liability adjustment | | 292 | 55,115 | | |
| 603 Enviromental interest and valuation adjustment | 395,009 | | | | |
| Total | 395,009 | 293 | 395,009 | | |
| 604 | | | | | |
| Total | | 294 | | | |
| Subtotal of other additions | | 199 | 805,866 | 805,866 | |
| **Total** (lines 101 to 199) | | 500 | 24,274,830 | 24,274,830 | B |
| Amount A **plus** amount B | | | | 24,363,830 | C |

## Deduct:

| | | | | |
|---|---|---|---|---|
| Capital cost allowance from Schedule 8 | 403 | 630,903 | | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 197,745 | | |
| Reserves from financial statements – balance at the beginning of the year | 414 | 23,030,407 | | |
| Contributions to deferred income plans from Schedule 15 | 417 | 101,721 | | |
| Subtotal of deductions | | 23,960,776 | ► | 23,960,776 |

## Other deductions:

| | | | | |
|---|---|---|---|---|
| Non-taxable/deductible other comprehensive income items | 347 | 2,000 | | |

## Miscellaneous other deductions:

| | | | | | | |
|---|---|---|---|---|---|---|
| 700 | Deductible removable costs | | 390 | 6,695 | | |
| 701 | See attached | | 391 | 113,606 | | |
| 702 | OPEB costs capitalized | | 392 | 68,491 | | |
| 703 | 2015 Ontario Apprentice credits accrual reversal | 8,684 | | | | |
| | Total | 8,684 | 393 | 8,684 | | |
| 704 | | | | | | |
| | | | | | | |
| | Total | | 394 | | | |
| | Subtotal of other deductions | | 499 | 199,476 | 199,476 | |
| | **Total** (lines 401 to 499) | | 510 | 24,160,252 | 24,160,252 | D |

**Net income (loss) for income tax purposes** (amount C **minus** amount D) . . . . 203,578 E

Enter amount E on line 300 of the T2 return.

# Attached Schedule with Total

Line 290 – Amount for line 600

Title Line 290 – Amount for line 600

| Description | Amount | |
|---|---|---|
| Class 12 - computer application software license | 884 | 00 |
| Class 8 - computer and other equipment cost < 2K | 403 | 00 |
| | | |
| **Total** | 1,287 | 00 |

# Attached Schedule with Total

Line 208 – Debt issue expense

Title Line 208 – Debt issue expense

| Description | Amount | |
|---|---|---|
| Bond Discount (761120) | 131 | 00 |
| Amortization underwriting fee (761780) | 514 | 00 |
| Amortization of Hedge loss (761770) | 2,316 | 00 |
| Amortization of Prospectus fees (761790) | 2 | 00 |
| | | |
| **Total** | 2,963 | 00 |

# Attached Schedule with Total

Line 391 – Amount for line 701

Title Line 391 – Amount for line 701

| Description | Amount | |
|---|---|---|
| Capitalized interest | 10,872 | 00 |
| Capitalized overhead | 101,112 | 00 |
| 20(1)(e) deduction re: prospectus fees | 33 | 00 |
| 20(1)(e) deduction re: underwriting fees | 1,589 | 00 |
| | | |
| **Total** | 113,606 | 00 |

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 5**

# Tax Calculation Supplementary – Corporations

| Corporation's name | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

## Part 1 – Allocation of taxable income

**100** ____________ Enter the Regulation that applies (402 to 413).

| A<br>Jurisdiction<br>Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. * | | B<br>Total salaries and wages paid in jurisdiction | C<br>(B x taxable income) / G | D<br>Gross revenue | E<br>(D x taxable income) / H | F<br>Allocation of taxable income (C + E) x 1/2**<br>(where either G or H is nil, do not multiply by 1/2) |
|---|---|---|---|---|---|---|
| Newfoundland and Labrador | 003 1 Yes | 103 | | 143 | | |
| Newfoundland and Labrador Offshore | 004 1 Yes | 104 | | 144 | | |
| Prince Edward Island | 005 1 Yes | 105 | | 145 | | |
| Nova Scotia | 007 1 Yes | 107 | | 147 | | |
| Nova Scotia Offshore | 008 1 Yes | 108 | | 148 | | |
| New Brunswick | 009 1 Yes | 109 | | 149 | | |
| Quebec | 011 1 Yes | 111 | | 151 | | |
| Ontario | 013 1 Yes | 113 | | 153 | | |
| Manitoba | 015 1 Yes | 115 | | 155 | | |
| Saskatchewan | 017 1 Yes | 117 | | 157 | | |
| Alberta | 019 1 Yes | 119 | | 159 | | |
| British Columbia | 021 1 Yes | 121 | | 161 | | |
| Yukon | 023 1 Yes | 123 | | 163 | | |
| Northwest Territories | 025 1 Yes | 125 | | 165 | | |
| Nunavut | 026 1 Yes | 126 | | 166 | | |
| Outside Canada | 1 Yes | 127 | | 167 | | |
| **Total** | | 129 G | | 169 H | | |

* "Permanent establishment" is defined in Regulation 400(2).

** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

**Notes:**

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. Special rules for establishing a corporation's gross revenue and salaries and wages attributable to a jurisdiction are provided in cases where the corporation operates in a partnership and the partnership had permanent establishments in more than one jurisdiction. See Guide T4068, *Guide for the Partnership Information Return* and prescribed Form T5013 Sch 5, *Allocation of Salaries and Wages, and Gross Revenue for Multiple Jurisdictions*.

## Part 2 – Ontario tax payable, tax credits, and rebates

| Total taxable income | Income eligible for small business deduction | Provincial or territorial allocation of taxable income | Provincial or territorial tax payable before credits |
|---|---|---|---|
| 203,578 | | 203,578 | 23,411 |

| Description | Line | Amount | Total | |
|---|---|---|---|---|
| **Ontario basic income tax** (from Schedule 500) | 270 | 23,411 | | |
| **Deduct:** Ontario small business deduction (from Schedule 500) | 402 | | | |
| Subtotal | | 23,411 | 23,411 | A6 |
| **Add:** | | | | |
| Ontario additional tax re Crown royalties (from Schedule 504) | 274 | | | |
| Ontario transitional tax debits (from Schedule 506) | 276 | | | |
| Recapture of Ontario research and development tax credit (from Schedule 508) | 277 | | | |
| Subtotal | | | | B6 |
| Subtotal (amount A6 **plus** amount B6) | | | 23,411 | C6 |
| **Deduct:** | | | | |
| Ontario resource tax credit (from Schedule 504) | 404 | | | |
| Ontario tax credit for manufacturing and processing (from Schedule 502) | 406 | | | |
| Ontario foreign tax credit (from Schedule 21) | 408 | | | |
| Ontario credit union tax reduction (from Schedule 500) | 410 | | | |
| Ontario political contributions tax credit (from Schedule 525) | 415 | | | |
| Subtotal | | | | D6 |
| Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") | | | 23,411 | E6 |
| **Deduct:** Ontario research and development tax credit (from Schedule 508) | 416 | | | |
| Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0") | | | 23,411 | F6 |
| **Deduct:** | | | | |
| Ontario corporate minimum tax credit (from Schedule 510) | 418 | | | |
| Ontario community food program donation tax credit for farmers (from Schedule 2) | 420 | | | |
| Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0") | | | 23,411 | G6 |
| **Add:** | | | | |
| Ontario corporate minimum tax (from Schedule 510) | 278 | | | |
| Ontario special additional tax on life insurance corporations (from Schedule 512) | 280 | | | |
| Subtotal | | | | H6 |
| Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) | | | 23,411 | I6 |
| **Deduct:** | | | | |
| Ontario qualifying environmental trust tax credit | 450 | | | |
| Ontario co-operative education tax credit (from Schedule 550) | 452 | 3,000 | | |
| Ontario apprenticeship training tax credit (from Schedule 552) | 454 | 4,684 | | |
| Ontario computer animation and special effects tax credit (from Schedule 554) | 456 | | | |
| Ontario film and television tax credit (from Schedule 556) | 458 | | | |
| Ontario production services tax credit (from Schedule 558) | 460 | | | |
| Ontario interactive digital media tax credit (from Schedule 560) | 462 | | | |
| Ontario sound recording tax credit (from Schedule 562) | 464 | | | |
| Ontario book publishing tax credit (from Schedule 564) | 466 | | | |
| Ontario innovation tax credit (from Schedule 566) | 468 | | | |
| Ontario business-research institute tax credit (from Schedule 568) | | | | |
| Subtotal | | 7,684 | 7,684 | J6 |
| **Net Ontario tax payable or refundable credit** (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255. | 290 | | 15,727 | K6 |

## Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

**Net provincial and territorial tax payable or refundable credits** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **255** 15,727

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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**Schedule 8**

# Capital Cost Allowance (CCA)

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes [ ] 2 No [X]

| | 1 Class number (See Note) 200 | Description | 2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201 | 3 Cost of acquisitions during the year (new property must be available for use)* 203 | 4 Adjustments and transfers** 205 | 5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207 | 6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211 | 7 Reduced undepreciated capital cost | 8 CCA rate % **** 212 | 9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213 | 10 Terminal loss (line 404 of Schedule 1) 215 | 11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217 | 12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | 15,336,034 | 113,867 | | 0 | 56,934 | 15,392,967 | 4 | 0 | 0 | 96,153 | 15,353,748 |
| 2. | 2 | | 91,755 | | | 0 | | 91,755 | 6 | 0 | 0 | 860 | 90,895 |
| 3. | 3 | | 749 | | | 0 | | 749 | 5 | 0 | 0 | 6 | 743 |
| 4. | 6 | | 5,913,778 | | | 0 | | 5,913,778 | 10 | 0 | 0 | 92,352 | 5,821,426 |
| 5. | 8 | | 1,087,790 | 16,076 | | 0 | 8,038 | 1,095,828 | 20 | 0 | 0 | 34,226 | 1,069,640 |
| 6. | 10 | | 841,965 | | | 0 | | 841,965 | 30 | 0 | 0 | 39,446 | 802,519 |
| 7. | 17 | | 16,446,093 | 175,312 | | 0 | 87,656 | 16,533,749 | 8 | 0 | 0 | 206,559 | 16,414,846 |
| 8. | 43.1 | | 1,269,833 | | | 0 | | 1,269,833 | 30 | 0 | 0 | 59,491 | 1,210,342 |
| 9. | 45 | | 2,406 | | | 0 | | 2,406 | 45 | 0 | 0 | 169 | 2,237 |
| 10. | 47 | | 7,642,785 | 893,285 | | 0 | 446,643 | 8,089,427 | 8 | 0 | 0 | 101,062 | 8,435,008 |
| 11. | 13 | Bisco Water Well | 46,548 | | | 0 | | 46,548 | NA | 0 | 0 | 293 | 46,255 |
| 12. | 13 | Hillsport Water Well | 39,835 | | | 0 | | 39,835 | NA | 0 | 0 | 156 | 39,679 |
| 13. | 13 | Oba Water Well | 17,994 | | | 0 | | 17,994 | NA | 0 | 0 | 70 | 17,924 |
| 14. | 94 | Construction in progress | 1,904,128 | | | 784,000 | | 1,120,128 | 0 | 0 | 0 | | 1,120,128 |
| 15. | 94 | Future use | 1,936,342 | | | 34,000 | | 1,902,342 | 0 | 0 | 0 | | 1,902,342 |
| 16. | 94 | Land | 359,667 | | | 0 | | 359,667 | 0 | 0 | 0 | | 359,667 |
| 17. | 94 | Landscaping | 47,952 | | | 0 | | 47,952 | 0 | 0 | 0 | | 47,952 |
| 18. | 12 | | | 775 | | 0 | 388 | 387 | 100 | 0 | 0 | 60 | 715 |
| | | **Totals** | 52,985,654 | 1,199,315 | | 818,000 | 599,659 | 52,767,310 | | | | 630,903 | 52,736,066 |

**Note:** Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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Canada

# Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

## Tax return

| | | | | |
|---|---|---|---|---|
| Additions for tax purposes – Schedule 8 regular classes | | 1,199,315 | | |
| Additions for tax purposes – Schedule 8 leasehold improvements | + | | | |
| Operating leases capitalized for book purposes | + | | | |
| Capital gain deferred | + | | | |
| Recapture deferred | + | | | |
| Deductible expenses capitalized for book purposes – Schedule 1 | + | -1,287 | | |
| Other (specify): | | | | |
| Current year capitalized allocations | + | 168,885 | | |
| Future use decrease | + | -34,180 | | |
| CIP decrease | + | -784,000 | | |
| Unreconciled difference- immaterial rounding | + | 267 | | |
| **Total additions per books** | = | 549,000 | ▶ | 549,000 |
| Proceeds up to original cost – Schedule 8 regular classes | | | | |
| Proceeds up to original cost – Schedule 8 leasehold improvements | + | | | |
| Proceeds in excess of original cost – capital gain | + | | | |
| Recapture deferred – as above | + | | | |
| Capital gain deferred – as above | + | | | |
| Pre V-day appreciation | + | | | |
| Other (specify): | | | | |
| | + | | | |
| **Total proceeds per books** | = | | ▶ – | |
| Depreciation and amortization per accounts – Schedule 1 | | | – | 428,000 |
| Loss on disposal of fixed assets per accounts | | | – | |
| Gain on disposal of fixed assets per accounts | | | + | |
| **Net change per tax return** | | | = | 121,000 |

## Financial statements

**Fixed assets (excluding land) per financial statements**

| | | |
|---|---|---|
| Closing net book value | | 42,670,000 |
| Opening net book value | – | 42,549,000 |
| **Net change per financial statements** | = | 121,000 |

If the amounts from the tax return and the financial statements differ, explain why below.

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**SCHEDULE 9**

# RELATED AND ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

| | Name 100 | Country of residence (other than Canada) 200 | Business number (see note 1) 300 | Relationship code (see note 2) 400 | Number of common shares you own 500 | % of common shares you own 550 | Number of preferred shares you own 600 | % of preferred shares you own 650 | Book value of capital stock 700 |
|---|---|---|---|---|---|---|---|---|---|
| 1. | HYDRO ONE LIMITED | CA | 80512 9962 RC0001 | 3 | | | | | |
| 2. | HYDRO ONE INC. | CA | 86999 4731 RC0001 | 1 | | | | | |
| 3. | 2486267 ONTARIO INC | CA | 80232 6124 RC0001 | 3 | | | | | |
| 4. | 2486268 ONTARIO INC | CA | 80167 4078 RC0001 | 3 | | | | | |
| 5. | HYDRO ONE NETWORKS INC. | CA | 87086 5821 RC0001 | 3 | | | | | |
| 6. | HYDRO ONE TELECOM INC. | CA | 86800 1066 RC0001 | 3 | | | | | |
| 7. | HYDRO ONE TELECOM LINK LIMITE | CA | 88786 7513 RC0001 | 3 | | | | | |
| 8. | MUNICIPAL BILLING SERVICES INC | CA | 87560 6519 RC0001 | 3 | | | | | |
| 9. | HYDRO ONE LAKE ERIE LINK MANA | CA | 87892 1519 RC0002 | 3 | | | | | |
| 10. | 1938454 ONTARIO INC. | CA | 86391 7795 RC0002 | 3 | | | | | |
| 11. | 1943404 ONTARIO INC. | CA | 86248 6123 RC0002 | 3 | | | | | |
| 12. | B2M GP INC. | CA | 81838 1840 RC0001 | 3 | | | | | |
| 13. | HYDRO ONE B2M HOLDINGS INC | CA | 82217 7531 RC0001 | 3 | | | | | |
| 14. | HYDRO ONE B2M LP INC. | CA | 81838 2046 RC0001 | 3 | | | | | |
| 15. | NORFOLK ENERGY INC | CA | 86289 0399 RC0001 | 3 | | | | | |
| 16. | NORFOLK POWER DISTRIBUTION I | CA | 86289 2593 RC0001 | 3 | | | | | |
| 17. | HALDIMAND COUNTY ENERGY INC | CA | 89076 2412 RC0001 | 3 | | | | | |
| 18. | HALDIMAND COUNTY HYDRO INC | CA | 89075 9814 RC0001 | 3 | | | | | |
| 19. | Woodstock Hydro Services Inc. | CA | 89909 5012 RC0001 | 3 | | | | | |
| 20. | 1937672 ONTARIO INC. | CA | 81722 4561 RC0001 | 3 | | | | | |
| 21. | 1937680 ONTARIO INC. | CA | 81930 4924 RC0001 | 3 | | | | | |
| 22. | 1937681 ONTARIO INC. | CA | 81722 4363 RC0001 | 3 | | | | | |
| 23. | Hydro One East-West Tie Inc. | CA | 80105 5880 RC0001 | 3 | | | | | |

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.

Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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Canada

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**SCHEDULE 10**

# CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

## Part 1 – Calculation of current year deduction and carry-forward

| | | | | |
|---|---|---|---|---|
| **Cumulative eligible capital - Balance at the end of the preceding taxation year** (if negative, enter "0") | | 200 | 18,089,492 | A |
| **Add:** Cost of eligible capital property acquired during the taxation year | 222 | | | |
| Other adjustments | 226 | | | |
| Subtotal (line 222 plus line 226) | x 3 / 4 = | | | B |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 | 228 | x 1 / 2 = | | C |
| amount B minus amount C (if negative, enter "0") | | | | D |
| Amount transferred on amalgamation or wind-up of subsidiary | | 224 | | E |
| Subtotal (add amounts A, D, and E) | | 230 | 18,089,492 | F |
| **Deduct:** Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year | 242 | | | G |
| The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) | 244 | | | H |
| Other adjustments | 246 | | | I |
| (add amounts G,H, and I) | x 3 / 4 = | 248 | | J |
| **Cumulative eligible capital balance** (amount F minus amount J) | | | 18,089,492 | K |

(if amount K is negative, enter "0" at line M and proceed to Part 2)

| | | | |
|---|---|---|---|
| Cumulative eligible capital for a property no longer owned after ceasing to carry on that business | 249 | | |
| amount K | 18,089,492 | | |
| **less** amount from line 249 | | | |
| **Current year deduction** | 18,089,492 x 7.00 % = 250 | 197,745 * | |
| (line 249 plus line 250) (enter this amount at line 405 of Schedule 1) | | 197,745 | 197,745 L |
| **Cumulative eligible capital – Closing balance** (amount K minus amount L) (if negative, enter "0") | 300 | | 17,891,747 M |

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

## Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

| | | | | |
|---|---|---|---|---|
| Amount from line K (show as positive amount) | | | | N |
| Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988 | | 400 | 1 | |
| Total of all amounts which reduced CEC in the current or prior years under subsection 80(7) | | 401 | 2 | |
| Total of CEC deductions claimed for taxation years beginning before July 1, 1988 | 402 | 3 | | |
| Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988 | 408 | 4 | | |
| Line 3 minus line 4 (if negative, enter "0") | | | 5 | |
| Total of lines 1, 2 and 5 | | | 6 | |
| Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400 | | 7 | | |
| Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000 | | 8 | | |
| Subtotal (line 7 plus line 8) | 409 | | 9 | |
| Line 6 minus line 9 (if negative, enter "0") | | | | O |
| Line N minus line O (if negative, enter "0") | | | | P |
| Line 5 | x 1 / 2 = | | | Q |
| Line P minus line Q (if negative, enter "0") | | | | R |
| Amount R | x 2 / 3 = | | | S |
| Amount N or amount O, whichever is less | | | | T |
| **Amount to be included in income** (amount S plus amount T) (enter this amount on line 108 of Schedule 1) | | 410 | | |

# Continuity of financial statement reserves (not deductible)

## Financial statement reserves (not deductible)

| | Description | Balance at the beginning of the year | Transfer on an amalgamation or the wind-up of a subsidiary | Add | Deduct | Balance at the end of the year |
|---|---|---|---|---|---|---|
| 1 | OPEB Liability | 14,081,620 | | | 191,390 | 13,890,230 |
| 2 | RPPP Rev Var (427191) | -2,863,877 | | 103,944 | | -2,759,933 |
| 3 | Enviromental Liability - LONG T | 11,812,664 | | | 761,583 | 11,051,081 |
| 4 | | | | | | |
| | Reserves from Part 2 of Schedule 13 | | | | | |
| | **Totals** | 23,030,407 | | 103,944 | 952,973 | 22,181,378 |

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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**SCHEDULE 14**

# MISCELLANEOUS PAYMENTS TO RESIDENTS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

| | Name of recipient 100 | Address of recipient 200 | Royalties 300 | Research and development fees 400 | Management fees 500 | Technical assistance fees 600 | Similar payments 700 |
|---|---|---|---|---|---|---|---|
| 1 | Hydro One Networks Inc. | 483 Bay Street<br>Toronto<br>ON CA<br>M5G 2P5 | | | 151,354 | | |
| 2 | Hydro One Inc | 483 Bay Street<br>Toronto<br>ON CA<br>M5G 2P5 | | | 7,970 | | |

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Canada

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**Schedule 15**

# Deferred Income Plans

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

| | Type of plan (see note 1) | Amount of contribution $ (see note 2) | Registration number (RPP, RSUBP, PRPP, and DPSP only) | Name of EPSP trust | Address of EPSP trust | T4PS slip(s) (see note 3) |
|---|---|---|---|---|---|---|
| | 100 | 200 | 300 | 400 | 500 | 600 |
| 1 | 1 | 339,070 | 1059104 | | | |

**Note 1**

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

**Note 2**

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . . . . . . . . . . . . . . . . 339,070 A

**Less:**

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 237,349 B

**Deductible amount for contributions to deferred income plans**
(amount A **minus** amount B) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . 101,721 C

Enter amount C on line 417 of Schedule 1

**Note 3**

T4PS slip(s) filed by: 1 – Trustee
2 – Employer (EPSP only)

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**Schedule 31**

# Investment Tax Credit – Corporations

## General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the *Income Tax Act*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim;*
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

## Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Expenditures for pre-production mining, apprenticeship, or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

## Detailed information (continued)

- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

## Part 1 – Investments, expenditures, and percentages

| **Investments** | **Specified percentage** |
|---|---|
| Qualified property acquired primarily for use in Atlantic Canada | 10 % |
| Qualified resource property acquired primarily for use in Atlantic Canada and acquired: | |
| – after March 28, 2012, and before 2014 | 10 % |
| – after 2013 and before 2016 | 5 % |
| – after 2015* | 0 % |
| **Expenditures** | |
| If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10) | 35 % |
| **Note:** If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**. | |
| If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada: | |
| – before 2014** | 20 % |
| – after 2013** | 15 % |
| If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012 | 10 % |
| If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***: | |
| – after March 28, 2012, and before 2013 | 10 % |
| – in 2013 | 5 % |
| – after 2013*** | 0 % |
| If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****: | |
| – after March 28, 2012, and before 2014**** | 10 % |
| – in 2014 | 7 % |
| – in 2015 | 4 % |
| – after 2015**** | 0 % |
| If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment | 10 % |
| If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children | 25 % |

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more information. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

## Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

**Note:** A CCPC calculating a refundable ITC is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and

one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

## Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . . . . . . . . . . . . . . . . . . . . . . . . **102** 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED* . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **103** ______

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see Guide RC4088, *General Index of Financial Information (GIFI)*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661.
Include 80% of the contributions made **after** 2012; for contributions made **before** 2013, include all of the contributions.

## Qualified Property and Qualified Resource Property

## Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

| Capital cost allowance class number **105** | Description of investment **110** | Date available for use **115** | Location used (province or territory) **120** | Amount of investment **125** |
|---|---|---|---|---|
| | | | | |

**Total of investments for qualified property and qualified resource property** ______ A1

## Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year . . . . . . . . B1

**Deduct:**

Credit deemed as a remittance of co-op corporations . . . . . . 210

Credit expired . . . . . . 215

Subtotal (line 210 **plus** line 215) C1

ITC at the beginning of the tax year (amount B1 **minus** amount C1) . . . . . . 220

**Add:**

Credit transferred on amalgamation or wind-up of subsidiary . . . . . . 230

ITC from repayment of assistance . . . . . . 235

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) . . . . . . x 10 % = 240

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) . . . . . x 5 % = 242

Credit allocated from a partnership . . . . . . 250

Subtotal (total of lines 230 to 250) D1

Total credit available (line 220 **plus** amount D1) . . . . . . E1

**Deduct:**

Credit deducted from Part I tax (enter at amount D8 in Part 30) . . . . . . 260

Credit carried back to the previous year(s) (from amount H1 in Part 6) . . . . . . a

Credit transferred to offset Part VII tax liability . . . . . . 280

Subtotal (total of line 260, amount a, and line 280) F1

Credit balance before refund (amount E1 **minus** amount F1) . . . . . . G1

**Deduct:**

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) . . . . . . 310

**ITC closing balance of investments from qualified property and qualified resource property** (amount G1 **minus** line 310) . . . . . . 320

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

## Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 901 | |
| 2nd previous tax year | | | | Credit to be applied | 902 | |
| 3rd previous tax year | | | | Credit to be applied | 903 | |

Total of lines 901 to 903 (enter amount H1 on line a in Part 5) H1

## Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5) . . . . . . I1

Credit balance before refund (from amount G1 in Part 5) . . . . . . J1

**Refund** ( 40 % of amount I1 or J1, whichever is less) . . . . . . K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

# SR&ED

## Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 557 on Form T661) . . . . . . . . . . . . . . . . . . . . . . . . . .

Contributions to agricultural organizations for SR&ED . . . . . . . .

**Deduct:**

Government assistance, non-government assistance, or contract payment . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .

Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)* . . . . . . . . . . . . . . . . . . . . ▶ +

Current expenditures (line 557 on Form T661 **plus** line 103 in Part 3)* . . . . . . . . . . . . . . . **350**

Capital expenditures incurred **before** 2014 (from line 558 on Form T661)** . . . . . . . . . . . . . . . . . . . . . . . . . . . . **360**

Repayments made in the year (from line 560 on Form T661) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **370**

**Qualified SR&ED expenditures** (total of lines 350 to 370) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **380**

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures. Capital cost allowance can be claimed for depreciable property acquired for use in SR&ED after 2013.

## Part 9 – Components of the SR&ED expenditure limit calculation

**Part 9 only applies if the corporation is a CCPC.**

**Note:** A CCPC that calculates an SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and

one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . . . . **385** 1 Yes ☐ 2 No ☐

Complete lines 390 and 398 if you answered **no** to the question on line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) . . . . . . . . . . . . . . . . . . . . . **390**

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **398**

* If either of the tax years referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

## Part 10 – SR&ED expenditure limit for a CCPC

**For a stand-alone corporation:** $ 8,000,000

**Deduct:**

Taxable income for the previous tax year (from line 390 in Part 9) or $500,000, whichever is more ______ x 10 = ______ A2

Excess ($8,000,000 **minus** amount A2; if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . B2

$ 40,000,000 **minus** line 398 in Part 9 . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ a

Amount a **divided** by $ 40,000,000 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . C2

**Expenditure limit for the stand-alone corporation** (amount B2 **multiplied** by amount C2)* . . . . . . . . . . . . . . . . . . . . D2

**For an associated corporation:**

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49* . . . . . . . . . . . . . . . . . . . . . **400** E2

**Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:**

Amount D2 or E2 ______ x $\frac{\text{Number of days in the tax year}}{365}$ 57 = . . . . . . . . . . . F2

**Your SR&ED expenditure limit for the year** (enter the amount from amount D2, E2, or F2, whichever applies) . . . . . . . **410**

* Amount D2 or E2 cannot be more than $3,000,000.

## Part 11 – Investment tax credits on SR&ED expenditures

| | | | | | | |
|---|---|---|---|---|---|---|
| Current expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less* | 420 | | x | 35 % | = | G2 |
| Line 350 **minus** line 410 (if negative, enter "0") | 430 | | x | 15 **% | = | H2 |
| Line 410 **minus** line 350 (if negative, enter "0") | | | b | | | |
| Capital expenditures (from line 360 in Part 8) or amount b above, whichever is less* | 440 | | x | 35 % | = | I2 |
| Line 360 **minus** amount b above (if negative, enter "0") | 450 | | x | 15 **% | = | J2 |

**Repayments** (amount from line 370 in Part 8) . . . . . . . .

| | | | | | | |
|---|---|---|---|---|---|---|
| If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.*** | 460 | | x | 35 % | = | c |
| | 480 | | x | 15 % | = | d |
| | | | | Subtotal (amount c **plus** amount d) | | K2 |

**Current-year SR&ED ITC** (total of amounts G2 to K2; enter on line 540 in Part 12) . . . . . . . . . . . . . . . . . . . . . . . . . L2

* For corporations that are not CCPCs, enter "0" for amounts G2 and I2.

** For tax years that end after 2013, the general SR&ED ITC rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013. If your rate is different than 15%, enter the amounts at lines 430 or 450 and use the appropriate rate instead of 15%.

*** The ITC on the repayment (the credit) is calculated using the ITC rate that you used to determine your ITC at the time your qualified expenditures for ITC purposes were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate. If the rate is different than 20% or 35%, enter the amount at line 480 and use the appropriate rate instead of 20%.

## Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | M2 |
| **Deduct:** | | | | |
| Credit deemed as a remittance of co-op corporations | 510 | | | |
| Credit expired | 515 | | | |
| Subtotal (line 510 **plus** line 515) | | | | N2 |
| ITC at the beginning of the tax year (amount M2 **minus** amount N2) | | | 520 | |
| **Add:** | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 530 | | | |
| Total current-year credit (from amount L2 in Part 11) | 540 | | | |
| Credit allocated from a partnership | 550 | | | |
| Subtotal (total of lines 530 to 550) | | | | O2 |
| Total credit available (line 520 **plus** amount O2) | | | | P2 |
| **Deduct:** | | | | |
| Credit deducted from Part I tax (enter at amount E8 in Part 30) | 560 | | | |
| Credit carried back to the previous year(s) (from amount S2 in Part 13) | | e | | |
| Credit transferred to offset Part VII tax liability | 580 | | | |
| Subtotal (total of line 560, amount e, and line 580) | | | | Q2 |
| Credit balance before refund (amount P2 **minus** amount Q2) | | | | R2 |
| **Deduct:** | | | | |
| Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) | | | 610 | |
| **ITC closing balance on SR&ED** (amount R2 **minus** line 610) | | | 620 | |

## Part 13 – Request for carryback of credit from SR&ED expenditures

| | Year | Month | Day | | | | |
|---|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 911 | | |
| 2nd previous tax year | | | | Credit to be applied | 912 | | |
| 3rd previous tax year | | | | Credit to be applied | 913 | | |
| | | | | Total of lines 911 to 913 (enter amount S2 at line e in Part 12) | | | S2 |

## Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes [ ] 2 No [X]

| | | |
|---|---|---|
| Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) | | f |
| Refundable credits (amount f or amount R2 in Part 12, whichever is less)* | | T2 |
| **Deduct:** | | |
| Amount T2 or amount G2 in Part 11, whichever is less | | U2 |
| Net amount (amount T2 **minus** amount U2; if negative, enter "0") | | V2 |
| Amount V2 **multiplied** by 40 % | | W2 |
| **Add:** | | |
| Amount U2 | | X2 |
| **Refund of ITC** (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) | | Y2 |

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

## Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

| | | |
|---|---|---|
| Credit balance before refund (from amount R2 in Part 12) | | Z2 |
| **Deduct:** | | |
| Amount Z2 or amount G2 in Part 11, whichever is less | | AA2 |
| Net amount (amount Z2 **minus** amount AA2; if negative, enter "0") | | BB2 |
| Amount BB2 or amount I2 in Part 11, whichever is less | | CC2 |
| Amount CC2 **multiplied** by 40 % | | DD2 |
| **Add :** | | |
| Amount AA2 | | EE2 |
| **Refund of ITC** (amount DD2 **plus** amount EE2) | | FF2 |

Enter FF2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

# Recapture – SR&ED

## Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

**Note:**

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

### Calculation 1 – If you meet all of the above conditions

| Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above 700 | Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710 | Amount from column 700 or 710, whichever is less |
|---|---|---|
| | | |

**Subtotal** (enter amount A3 on line C3 in Part 17) A3

### Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line B3.

| A<br>Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement<br>720 | B<br>Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition<br>730 | C<br>Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.)<br>740 | D<br>Amount determined by the formula (A x B) – C | E<br>ITC earned by the transferee for the qualified expenditures that were transferred<br>750 | F<br>Amount from column D or E, whichever is less |
|---|---|---|---|---|---|
| | | | | | |

**Subtotal** (total of column F)
(enter amount B3 on line D3 in Part 17) B3

## Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

### Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line E3 in Part 17) **760** ____________

## Part 17 – Total recapture of SR&ED investment tax credit

| | | |
|---|---|---|
| Recaptured ITC from calculation 1, amount A3 in Part 16 | | C3 |
| Recaptured ITC from calculation 2, amount B3 in Part 16 | | D3 |
| Recaptured ITC from calculation 3, line 760 in Part 16 | | E3 |
| **Total recapture of SR&ED investment tax credit** (total of amounts C3 to E3) | | F3 |

Enter amount F3 on line A8 in Part 29.

# Pre-Production Mining

## Part 18 – Pre-production mining expenditures

### Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

| List of minerals 800 | Project name 805 |
|---|---|
| | |

| Mineral title 806 | Mining division 807 |
|---|---|
| | |

### Pre-production mining expenditures*

**Exploration:**

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

| | | |
|---|---|---|
| Prospecting | 810 | |
| Geological, geophysical, or geochemical surveys | 811 | |
| Drilling by rotary, diamond, percussion, or other methods | 812 | |
| Trenching, digging test pits, and preliminary sampling | 813 | |

**Development:**

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

| | | |
|---|---|---|
| Clearing, removing overburden, and stripping | 820 | |
| Sinking a mine shaft, constructing an adit, or other underground entry | 821 | |

Other pre-production mining expenditures incurred in the tax year:

| Description 825 | Amount 826 |
|---|---|
| | |
| Total of column 826 | |

A4

| | | |
|---|---|---|
| Total pre-production mining expenditures (total of lines 810 to 821 and amount A4) | 830 | |

**Deduct:**

| | | |
|---|---|---|
| Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to on line 830 above | 832 | |
| Excess (line 830 **minus** line 832) (if negative, enter "0") | | B4 |

**Add:**

| | | |
|---|---|---|
| Repayments of government and non-government assistance | 835 | |
| **Pre-production mining expenditures** (amount B4 **plus** line 835) | | C4 |

* A pre-production mining expenditure is defined under subsection 127(9).

## Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year . . . . . . . . . . D4

**Deduct:**

Credit deemed as a remittance of co-op corporations . . . . . . 841

Credit expired . . . . . . 845

Subtotal (line 841 **plus** line 845) E4

ITC at the beginning of the tax year (amount D4 **minus** amount E4) . . . . . . 850

**Add:**

Credit transferred on amalgamation or wind-up of subsidiary . . . . . . 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part from amount C4 in Part 18) . . 870 x 10 % = a

Pre-production mining exploration expenditures incurred in 2013 (applicable part from amount C4 in Part 18) . . 872 x 5 % = b

Pre-production mining development expenditures incurred in 2014 (applicable part from amount C4 in Part 18) . . 874 x 7 % = c

Pre-production mining development expenditures incurred in 2015 (applicable part from amount C4 in Part 18) . . 876 x 4 % = d

Current year credit (total of amounts a to d) 880 F4

Total credit available (total of lines 850, 860, and amount F4) . . . . . . G4

**Deduct:**

Credit deducted from Part I tax (enter at amount F8 in Part 30) . . . . . . 885

Credit carried back to the previous year(s) (from amount I4 in Part 20) . . . . . . e

Subtotal (line 885 **plus** amount e) H4

**ITC closing balance from pre-production mining expenditures** (amount G4 **minus** amount H4) . . . . . . 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

## Part 20 – Request for carryback of credit from pre-production mining expenditures

| | Year | Month | Day | | |
|---|---|---|---|---|---|
| 1st previous tax year | | | | . . . . . . Credit to be applied | 921 |
| 2nd previous tax year | | | | . . . . . . Credit to be applied | 922 |
| 3rd previous tax year | | | | . . . . . . Credit to be applied | 923 |

Total of lines 921 to 923 (enter amount I4 on line e in Part 19) I4

# Apprenticeship Job Creation

## Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

| | A<br>Contract number<br>(SIN or name of apprentice)<br>601 | B<br>Name of eligible trade<br>602 | C<br>Eligible salary and wages*<br>603 | D<br>Column C x 10 %<br>604 | E<br>Lesser of column D or $ 2,000<br>605 | |
|---|---|---|---|---|---|---|
| 1. | [redacted] | 309A | 1,700 | 170 | 170 | |
| | | | | Total current-year credit (total of column E) (enter amount A5 on line 640 in Part 22) | 170 | A5 |

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received.

## Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | B5 |
| **Deduct:** | | | | |
| Credit deemed as a remittance of co-op corporations | 612 | | | |
| Credit expired after 20 tax years | 615 | | | |
| Subtotal (line 612 **plus** line 615) | | | | C5 |
| ITC at the beginning of the tax year (amount B5 **minus** amount C5) | 625 | | | |
| **Add:** | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 630 | | | |
| ITC from repayment of assistance | 635 | | | |
| Total current-year credit (from amount A5 in Part 21) | 640 | 170 | | |
| Credit allocated from a partnership | 655 | | | |
| Subtotal (total of lines 630 to 655) | | 170 | 170 | D5 |
| Total credit available (line 625 **plus** amount D5) | | | 170 | E5 |
| **Deduct:** | | | | |
| Credit deducted from Part I tax (enter on line G8 in Part 30) | 660 | 170 | | |
| Credit carried back to the previous year(s) (from amount G5 in Part 23) | | | | a |
| Subtotal (line 660 **plus** amount a) | | 170 | 170 | F5 |
| **ITC closing balance from apprenticeship job creation expenditures** (amount E5 **minus** amount F5) | 690 | | | |

## Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 931 | |
| 2nd previous tax year | | | | Credit to be applied | 932 | |
| 3rd previous tax year | | | | Credit to be applied | 933 | |
| | | | | Total of lines 931 to 933 (enter amount G5 on line a in Part 22) | | G5 |

# Child Care Spaces

## Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

### Cost of depreciable property from the current tax year

| | Capital cost allowance class number 665 | Description of investment 675 | Date available for use 685 | Amount of investment 695 |
|---|---|---|---|---|
| 1. | | | | |

Total cost of depreciable property from the current tax year (total of column 695) 715 ______

**Add:**

Specified child care start-up expenditures from the current tax year . . . . . 705 ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ______ A6

**Deduct:**

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . . 725 ______

Excess (amount A6 **minus** line 725) (if negative, enter "0") . . . . . ______ B6

**Add:**

Repayments by the corporation of government and non-government assistance . . . . . 735 ______

**Total eligible expenditures for child care spaces** (amount B6 **plus** line 735) . . . . . 745 ______

## Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 24) . . . . . ______ x 25 % = ______ C6

Number of child care spaces . . . . . 755 ______ x $ 10,000 = ______ D6

**ITC from child care spaces expenditures** (amount C6 or D6, whichever is less) . . . . . ______ E6

## Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | F6 |
| **Deduct:** | | | | |
| Credit deemed as a remittance of co-op corporations | 765 | | | |
| Credit expired after 20 tax years | 770 | | | |
| Subtotal (line 765 **plus** line 770) | | | | G6 |
| ITC at the beginning of the tax year (amount F6 **minus** amount G6) | | | 775 | |
| **Add:** | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 777 | | | |
| Total current-year credit (from amount E6 in Part 25) | 780 | | | |
| Credit allocated from a partnership | 782 | | | |
| Subtotal (total of lines 777 to 782) | | | | H6 |
| Total credit available (line 775 **plus** amount H6) | | | | I6 |
| **Deduct:** | | | | |
| Credit deducted from Part I tax (enter on line H8 in Part 30) | 785 | | | |
| Credit carried back to the previous year(s) (from amount K6 in Part 27) | | a | | |
| Subtotal (line 785 **plus** amount a) | | | | J6 |
| **ITC closing balance from child care spaces expenditures** (amount I6 **minus** amount J6) | | | 790 | |

## Part 27 – Request for carryback of credit from child care space expenditures

| | Year Month Day | | | |
|---|---|---|---|---|
| 1st previous tax year | 2015-11-04 | Credit to be applied | 941 | |
| 2nd previous tax year | 2015-10-31 | Credit to be applied | 942 | |
| 3rd previous tax year | 2014-12-31 | Credit to be applied | 943 | |
| | | Total of lines 941 to 943 (enter amount K6 on line a in Part 26) | | K6 |

## Recapture – Child Care Spaces

### Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

the new child care space is no longer available; or

property that was an eligible expenditure for the child care space is:

– disposed of or leased to a lessee; or
– converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . . . . . . . . . . . . . . . . . . . . . . **792** ______

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . . . . . . . . . . . . . . . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ A7

**Corporate partnerships**

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

**Corporate partner's share of the excess of ITC** **799** ______

**Total recapture of child care spaces investment tax credit** (total of line 792, amount A7, and line 799) . . . . . . . . . . . . . . ______ B7
Enter amount B7 on line B8 in Part 29.

## Summary of Investment Tax Credits

### Part 29 – Total recapture of investment tax credit

| | | |
|---|---|---|
| Recaptured SR&ED ITC (from amount F3 in Part 17) | | A8 |
| Recaptured child care spaces ITC (from amount B7 in Part 28) | | B8 |
| **Total recapture of investment tax credit** (amount A8 **plus** amount B8) | | C8 |

Enter amount C8 on line 602 of the T2 return.

### Part 30 – Total ITC deducted from Part I tax

| | | |
|---|---|---|
| ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) | | D8 |
| ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) | | E8 |
| ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) | | F8 |
| ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) | 170 | G8 |
| ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) | | H8 |
| **Total ITC deducted from Part I tax** (total of amounts D8 to H8) | 170 | I8 |

Enter amount I8 on line 652 of the T2 return.

# Summary of Investment Tax Credit Carryovers

## Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

**Current year**

| Addition current year (A) | Applied current year (B) | Claimed as a refund (C) | Carried back (D) | ITC end of year (A-B-C-D) |
|---|---|---|---|---|
| 170 | 170 | | | |

**Prior years**

| Taxation year | ITC beginning of year (E) | Adjustments (F) | Applied current year (G) | ITC end of year (E-F-G) |
|---|---|---|---|---|
| 2015-11-04 | | | | |
| 2015-10-31 | | | | |
| 2014-12-31 | | | | |
| 2013-12-31 | | | | |
| 2012-12-31 | | | | |
| 2011-12-31 | | | | |
| 2010-12-31 | | | | |
| 2009-12-31 | | | | |
| 2008-12-31 | | | | |
| 2007-12-31 | | | | * |
| 2006-12-31 | | | | |
| 2005-12-31 | | | | |
| 2004-12-31 | | | | |
| 2003-12-31 | | | | |
| 2002-12-31 | | | | |
| 2001-12-31 | | | | |
| 2000-12-31 | | | | |
| 1999-12-31 | | | | |
| 1999-03-31 | | | | |
| 1998-03-31 | | | | * |
| **Total** | | | | |

B+C+D+G **Total ITC utilized** 170

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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**Schedule 33**

# Taxable Capital Employed in Canada – Large Corporations

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

## Part 1 – Capital

**Add** the following year-end amounts:

| Description | Line | Amount | Total |
|---|---|---|---|
| Reserves that have not been deducted in calculating income for the year under Part I | 101 | 22,181,378 | |
| Capital stock (or members' contributions if incorporated without share capital) | 103 | 5,000,000 | |
| Retained earnings | 104 | | |
| Contributed surplus | 105 | | |
| Any other surpluses | 106 | | |
| Deferred unrealized foreign exchange gains | 107 | | |
| All loans and advances to the corporation | 108 | | |
| All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations | 109 | 33,000,000 | |
| Any dividends declared but not paid by the corporation before the end of the year | 110 | | |
| All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year | 111 | | |
| The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below) | 112 | | |
| Subtotal (**add** lines 101 to 112) | | 60,181,378 | 60,181,378 A |

**Note:**

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
- a) those lines applied to partnerships in the same manner that they apply to corporations, and
- b) those amounts were computed without reference to amounts owing by the partnership
  - (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
  - (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

## Part 1 – Capital (continued)

| | | | | |
|---|---|---|---|---|
| Subtotal A (from page 1) | | | 60,181,378 | A |
| **Deduct** the following amounts: | | | | |
| Deferred tax debit balance at the end of the year | 121 | 3,930,000 | | |
| Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year | 122 | 4,913,000 | | |
| To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year. | 123 | | | |
| Deferred unrealized foreign exchange losses at the end of the year | 124 | | | |
| Subtotal (**add** lines 121 to 124) | | 8,843,000 | 8,843,000 | B |
| **Capital for the year** (amount A **minus** amount B) (if negative, enter "0") | 190 | | 51,338,378 | |

## Part 2 – Investment allowance

**Add** the carrying value at the end of the year of the following assets of the corporation:

| | | |
|---|---|---|
| A share of another corporation | 401 | |
| A loan or advance to another corporation (other than a financial institution) | 402 | 1,070,000 |
| A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution) | 403 | |
| Long-term debt of a financial institution | 404 | |
| A dividend payable on a share of the capital stock of another corporation | 405 | |
| A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(*d*)), or another partnership described in paragraph 181.2(4)(*d.1*) | 406 | |
| An interest in a partnership (see note 2 below) | 407 | |
| **Investment allowance for the year** (add lines 401 to 407) | 490 | 1,070,000 |

**Notes:**

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

## Part 3 – Taxable capital

| | | | |
|---|---|---|---|
| Capital for the year (line 190) | | 51,338,378 | C |
| **Deduct:** Investment allowance for the year (line 490) | | 1,070,000 | D |
| **Taxable capital for the year** (amount C **minus** amount D) (if negative, enter "0") | 500 | 50,268,378 | |

## Part 4 – Taxable capital employed in Canada

**To be completed by a corporation that was resident in Canada at any time in the year**

| Taxable capital for the year (line 500) | | Taxable income earned in Canada / Taxable income | | | | | |
|---|---|---|---|---|---|---|---|
| 50,268,378 | x | Taxable income earned in Canada | **610** | 203,578 / 203,578 | = | **Taxable capital employed in Canada** **690** | 50,268,378 |

**Notes:** 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

**To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada**

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ______

**Deduct** the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . . . . . . . . . . . . . . . . . **711** ______

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **712** ______

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . . . . . . . . **713** ______

Total deductions (**add** lines 711, 712, and 713) ______ ______ E

**Taxable capital employed in Canada** (line 701 **minus** amount E) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . **790** ______

**Note:** Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

## Part 5 – Calculation for purposes of the small business deduction

**This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.**

Taxable capital employed in Canada (amount from line 690) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ F

**Deduct:** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") ______ H

**Calculation for purposes of the small business deduction** (amount H x 0.225%) . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ I

Enter this amount at line 415 of the T2 return.

# Attached Schedule with Total

Part 1 – Deferred tax debit balance at the end of the year

Title Part 1 – Deferred tax debit balance at the end of the year

| Description | Amount |
|---|---|
| deferred income tax assets short term | 125,000 00 |
| deferred income tax assets long term | 3,805,000 00 |
| | |
| **Total** | 3,930,000 00 |

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**SCHEDULE 50**

# SHAREHOLDER INFORMATION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

| | Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) | Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") | Social insurance number | Trust number | Percentage common shares | Percentage preferred shares |
|---|---|---|---|---|---|---|
| | 100 | 200 | 300 | 350 | 400 | 500 |
| 1 | Hydro One Inc. | 86999 4731 RC0001 | | | 100.000 | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |

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**Schedule 88**

# Internet Business Activities

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- File this schedule if your corporation earns income from one or more webpages or websites.
- You may earn income from your webpages or websites if:
  - you sell goods and/or services on your own pages or websites. You may have a shopping cart and process payment transactions yourself or through a third-party service;
  - your site doesn't support transactions but your customers call, complete, and submit a form, or email you to make a purchase, order, booking, and others;
  - you sell goods and/or services on auction, marketplace, or similar websites operated by others; or
  - you earn income from advertising, income programs, or traffic your site generates. For example:
    - static advertisements you place on your site for other businesses
    - affiliate programs
    - advertising programs such as Google AdSense or Microsoft adCentre
    - other types of traffic programs.
- Also file this schedule if you don't have a website but you have created a profile or other page describing your business on blogs, auction, market place, or any other portal or directory websites from which you earn income.
- File this schedule with your *T2 – Corporation Income Tax Return*.

How many Internet webpages or websites does your corporation earn income from? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1

Provide the Internet webpage or website addresses (also known as URL addresses)*:

http:// http://www.hydroone.com/OURCOMMITMENT/REMOTECOMMUNITIES/Pages/home.aspx

http://

http://

http://

http://

What is the percentage of the corporation's gross revenue generated from the Internet in comparison to the corporation's total gross revenue? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 0.001 %

* If you have more than five websites, enter the addresses of those that generate the most Internet income. If you don't have a website but you have created a profile or other page describing your business on blogs, auction, market place, or any other portal or directory websites, enter the addresses of the pages if they generate income.



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**Schedule 500**

# Ontario Corporation Tax Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

## Part 1 – Ontario basic rate of tax for the year

**Ontario basic rate of tax for the year** . . . . . . . . 11.5 % A

## Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . . . . 203,578 B

**Ontario basic income tax**: amount B **multiplied** by Ontario basic rate of tax for the year (rate A from Part 1) . . . . . . . . 23,411 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

## Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

| | | |
|---|---|---|
| Income from active business carried on in Canada (amount from line 400 of the T2 return) | | 1 |
| Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) | | 2 |
| Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) | | 3 |

**Ontario business limit reduction:**

Amount from line 3 ______ a

**Deduct:**

Amount from line E of the T2 return ______ x Number of days in the tax year after May 1, 2014 / Number of days in the tax year = 57 / 57 = ______ b

Reduced Ontario business limit (amount a **minus** amount b) (if negative, enter "0") ______ ► ______ 4

Enter the least of amounts 1, 2, 3, and 4 ______ D

Ontario domestic factor (ODF): Ontario taxable income * / Taxable income earned in all provinces and territories ** = 203,578.00 / 203,578 = 1.00000 E

Amount D × ODF (line E) ______ c

Ontario taxable income (amount B from Part 2) 203,578 d

Ontario small business income (lesser of amount c and amount d) ______ F

OSBD rate for the year 7 % G

**Ontario small business deduction**: amount F **multiplied** by rate G ______ H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

## Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

**Ontario adjusted small business income** (lesser of amount D and amount d from Part 3) ______ I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

## Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ J

**Deduct:**

Ontario adjusted small business income (amount I from Part 4) . . . . . . . . . . . . . . . . . . . . . . . ______ K

Subtotal (amount J **minus** amount K) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . ______ L

Amount L **multiplied** by rate G from Part 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ M

Ontario domestic factor (line E from Part 3) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1.00000 N

**Ontario credit union tax reduction** (amount M **multiplied** by ODF from line N) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ O

Enter amount O on line 410 of Schedule 5.

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**Schedule 510**

# Ontario Corporate Minimum Tax

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Determination of CMT applicability

| | | |
|---|---|---|
| Total assets of the corporation at the end of the tax year * | 112 | 71,546,000 |
| Share of total assets from partnership(s) and joint venture(s) * | 114 | |
| Total assets of associated corporations (amount from line 450 on Schedule 511) | 116 | 10,000,000,000 |
| Total assets (total of lines 112 to 116) | | 10,071,546,000 |
| Total revenue of the corporation for the tax year ** | 142 | 48,961,228 |
| Share of total revenue from partnership(s) and joint venture(s) ** | 144 | |
| Total revenue of associated corporations (amount from line 550 on Schedule 511) | 146 | 5,000,000,000 |
| Total revenue (total of lines 142 to 146) | | 5,048,961,228 |

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
– Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
– The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
– The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

## Part 2 – Adjusted net income/loss for CMT purposes

| | | | | |
|---|---|---|---|---|
| Net income/loss per financial statements * | | | 210 | 89,000 |
| **Add** (to the extent reflected in income/loss): | | | | |
| Provision for current income taxes/cost of current income taxes | 220 | 383,000 | | |
| Provision for deferred income taxes (debits)/cost of future income taxes | 222 | | | |
| Equity losses from corporations | 224 | | | |
| Financial statement loss from partnerships and joint ventures | 226 | | | |
| Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act | 230 | | | |
| **Other additions** (see note below): | | | | |
| Share of adjusted net income of partnerships and joint ventures ** | 228 | | | |
| Total patronage dividends received, not already included in net income/loss | 232 | | | |
| 281 | 282 | | | |
| 283 | 284 | | | |
| Subtotal | | 383,000 | | 383,000 A |
| **Deduct** (to the extent reflected in income/loss): | | | | |
| Provision for recovery of current income taxes/benefit of current income taxes | 320 | | | |
| Provision for deferred income taxes (credits)/benefit of future income taxes | 322 | | | |
| Equity income from corporations | 324 | | | |
| Financial statement income from partnerships and joint ventures | 326 | | | |
| Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act | 330 | | | |
| Dividends not taxable under section 83 of the federal Act (from Schedule 3) | 332 | | | |
| Gain on donation of listed security or ecological gift | 340 | | | |
| Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act *** | 342 | | | |
| Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act **** | 344 | | | |
| Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act ***** | 346 | | | |
| Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act | 348 | | | |
| **Other deductions** (see note below): | | | | |
| Share of adjusted net loss of partnerships and joint ventures ** | 328 | | | |
| Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3 | 334 | | | |
| Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss | 336 | | | |
| Patronage dividends paid (from Schedule 16) not already included in net income/loss | 338 | | | |
| 381 Other comprehensive income | 382 | 2,000 | | |
| 383 | 384 | | | |
| 385 | 386 | | | |
| 387 | 388 | | | |
| 389 | 390 | | | |
| Subtotal | | 2,000 | | 2,000 B |
| Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B) | | | 490 | 470,000 |

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

**Note**

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

## Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

## Part 3 – CMT payable

| | | | | |
|---|---|---|---|---|
| Adjusted net income for CMT purposes (line 490 in Part 2, if positive) | **515** | | 470,000 | |
| **Deduct:** | | | | |
| CMT loss available (amount R from Part 7) | | | | |
| **Minus:** Adjustment for an acquisition of control * | **518** | | | |
| Adjusted CMT loss available | | | | C |
| Net income subject to CMT calculation (if negative, enter "0") | **520** | | 470,000 | |

Amount from line 520: 470,000 x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year 57) x 4 % = ______ 1

Amount from line 520: 470,000 x (Number of days in the tax year after June 30, 2010 57 / Number of days in the tax year 57) x 2.7 % = 12,690 2

Subtotal (amount 1 **plus** amount 2) . . . 12,690 3

| | | | |
|---|---|---|---|
| Gross CMT: amount on line 3 above x OAF ** | **540** | 12,690 | |
| **Deduct:** | | | |
| Foreign tax credit for CMT purposes *** | **550** | | |
| CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") | | 12,690 | D |
| **Deduct:** | | | |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 23,411 | |
| Net CMT payable (if negative, enter "0") | | | E |

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

**Ontario allocation factor** . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

## Part 4 – Calculation of CMT credit carryforward

| | | | | |
|---|---|---|---|---|
| CMT credit carryforward at the end of the previous tax year * | | G | | |
| **Deduct:** | | | | |
| CMT credit expired * | 600 | | | |
| CMT credit carryforward at the beginning of the current tax year * (see note below) | | | 620 | |
| **Add:** | | | | |
| CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) | | | 650 | |
| CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) | | | | H |
| **Deduct:** | | | | |
| CMT credit deducted in the current tax year (amount P from Part 5) | | | | I |
| Subtotal (amount H **minus** amount I) | | | | J |
| **Add:** | | | | |
| Net CMT payable (amount E from Part 3) | | | | |
| SAT payable (amount O from Part 6 of Schedule 512) | | | | |
| Subtotal | | | | K |
| CMT credit carryforward at the end of the tax year (amount J **plus** amount K) | | | 670 | L |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

**Note:** If you entered an amount on line 620 or line 650, complete Part 6.

## Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

| | | | | |
|---|---|---|---|---|
| CMT credit available for the tax year (amount H from Part 4) | | | | M |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 23,411 1 | | |
| For a corporation that is not a life insurance corporation: | | | | |
| CMT after foreign tax credit deduction (amount D from Part 3) | 12,690 2 | | | |
| For a life insurance corporation: | | | | |
| Gross CMT (line 540 from Part 3) | 3 | | | |
| Gross SAT (line 460 from Part 6 of Schedule 512) | 4 | | | |
| The **greater** of amounts 3 and 4 | 5 | | | |
| **Deduct:** line 2 or line 5, whichever applies: | | 12,690 6 | | |
| Subtotal (if negative, enter "0") | | 10,721 | 10,721 | N |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 23,411 | | |
| **Deduct:** | | | | |
| Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) | | 7,684 | | |
| Subtotal (if negative, enter "0") | | 15,727 | 15,727 | O |
| CMT credit deducted in the current tax year (least of amounts M, N, and O) | | | | P |

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

## Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | CMT credit balance * |
|---|---|
| 10th previous tax year | 680 |
| 9th previous tax year | 681 |
| 8th previous tax year | 682 |
| 7th previous tax year | 683 |
| 6th previous tax year | 684 |
| 5th previous tax year | 685 |
| 4th previous tax year | 686 |
| 3rd previous tax year | 687 |
| 2nd previous tax year | 688 |
| 1st previous tax year | 689 |
| Total ** | |

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

## Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . . . . . . . . . . . . . . . . . . . . Q

**Deduct:**

CMT loss expired * . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . . . . . . . . . . . 720

**Add:**

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . . . . . . . . . . . . . . 750

CMT loss available (line 720 **plus** line 750) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . R

**Deduct:**

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . . . . . .

Subtotal (if negative, enter "0") S

**Add:**

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . . . . . . . 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . . . . . . . . . . . . . . . . . . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

**Note:** If you entered an amount on line 720 or line 750, complete Part 8.

## Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | Balance earned in a tax year ending before March 23, 2007 * | Balance earned in a tax year ending after March 22, 2007 ** |
|---|---|---|
| 10th previous tax year | 810 | 820 |
| 9th previous tax year | 811 | 821 |
| 8th previous tax year | 812 | 822 |
| 7th previous tax year | 813 | 823 |
| 6th previous tax year | 814 | 824 |
| 5th previous tax year | 815 | 825 |
| 4th previous tax year | 816 | 826 |
| 3rd previous tax year | 817 | 827 |
| 2nd previous tax year | 818 | 828 |
| 1st previous tax year | | 829 |
| Total *** | | |

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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**SCHEDULE 511**

# ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 1 | HYDRO ONE LIMITED | 80512 9962 RC0001 | 0 | 0 |
| 2 | HYDRO ONE INC. | 86999 4731 RC0001 | 0 | 0 |
| 3 | 2486267 ONTARIO INC | 80232 6124 RC0001 | 0 | 0 |
| 4 | 2486268 ONTARIO INC | 80167 4078 RC0001 | 0 | 0 |
| 5 | HYDRO ONE NETWORKS INC. | 87086 5821 RC0001 | 10,000,000,000 | 5,000,000,000 |
| 6 | HYDRO ONE TELECOM INC. | 86800 1066 RC0001 | 0 | 0 |
| 7 | HYDRO ONE TELECOM LINK LIMITED | 88786 7513 RC0001 | 0 | 0 |
| 8 | MUNICIPAL BILLING SERVICES INC | 87560 6519 RC0001 | 0 | 0 |
| 9 | HYDRO ONE LAKE ERIE LINK MANAGEMENT INC | 87892 1519 RC0002 | 0 | 0 |
| 10 | 1938454 ONTARIO INC. | 86391 7795 RC0002 | 0 | 0 |
| 11 | 1943404 ONTARIO INC. | 86248 6123 RC0002 | 0 | 0 |
| 12 | B2M GP INC. | 81838 1840 RC0001 | 0 | 0 |
| 13 | HYDRO ONE B2M HOLDINGS INC | 82217 7531 RC0001 | 0 | 0 |
| 14 | HYDRO ONE B2M LP INC. | 81838 2046 RC0001 | 0 | 0 |
| 15 | NORFOLK ENERGY INC | 86289 0399 RC0001 | 0 | 0 |
| 16 | NORFOLK POWER DISTRIBUTION INC | 86289 2593 RC0001 | 0 | 0 |
| 17 | HALDIMAND COUNTY ENERGY INC | 89076 2412 RC0001 | 0 | 0 |
| 18 | HALDIMAND COUNTY HYDRO INC | 89075 9814 RC0001 | 0 | 0 |
| 19 | Woodstock Hydro Services Inc. | 89909 5012 RC0001 | 0 | 0 |
| 20 | 1937672 ONTARIO INC. | 81722 4561 RC0001 | 0 | 0 |
| 21 | 1937680 ONTARIO INC. | 81930 4924 RC0001 | 0 | 0 |
| 22 | 1937681 ONTARIO INC. | 81722 4363 RC0001 | 0 | 0 |
| 23 | Hydro One East-West Tie Inc. | 80105 5880 RC0001 | 0 | 0 |
| | | **Total** | 450 10,000,000,000 | 550 5,000,000,000 |

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511

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**SCHEDULE 550**

# ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

| 110 Name of person to contact for more information | 120 Telephone number including area code |
|---|---|
| GLENDY CHEUNG | (416) 345-6812 |

Is the claim filed for a CETC earned through a partnership?* . . . . . . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

## Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **300** 100,000

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[ 5\% \times \left( \frac{\text{amount on line 300} \;\textbf{minus}\; \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **310** 15.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[ 5\% \times \left( \frac{\text{amount on line 300} \;\textbf{minus}\; \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **312** 30.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

| | **A**<br>Name of university, college, or other eligible educational institution<br>**400** | **B**<br>Name of qualifying co-operative education program<br>**405** |
|---|---|---|
| 1. | University of Toronto | Mechanical Engineering |

| | **C**<br>Name of student<br>**410** | **D**<br>Start date of WP (see note 1 below)<br>**430** | **E**<br>End date of WP (see note 2 below)<br>**435** |
|---|---|---|---|
| 1. | [redacted] | 2015-09-01 | 2015-12-31 |

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

## Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

| | F1<br>Eligible expenditures before March 27, 2009<br>(see note 1 below)<br>450 | Eligible percentage before March 27, 2009<br>(from line 310 in Part 3) | F2<br>Eligible expenditures after March 26, 2009<br>(see note 1 below)<br>452 | Eligible percentage after March 26, 2009<br>(from line 310a in Part 3) | X<br>Number of consecutive weeks of the WP completed by the student before March 27, 2009<br>(see note 3 below) | Y<br>Total number of consecutive weeks of the student's WP<br>(see note 3 below) |
|---|---|---|---|---|---|---|
| 1. | | 15.000 % | 20,866 | 30.000 % | | 16 |

| | G<br>Eligible amount<br>(eligible expenditures **multiplied** by eligible percentage)<br>(see note 2 below)<br>460 | H<br>Maximum CETC per WP<br>(see note 3 below)<br>462 | I<br>CETC on eligible expenditures<br>(column G or H, whichever is less)<br>470 | J<br>CETC on repayment of government assistance<br>(see note 4 below)<br>480 | K<br>CETC for each WP<br>(column I or column J)<br>490 |
|---|---|---|---|---|---|
| 1. | 6,260 | 3,000 | 3,000 | | 3,000 |

**Ontario co-operative education tax credit** (total of amounts in column K) **500** 3,000 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = . . . . . . . . . . . . . . . . . . . . . . . ________ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

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**Schedule 552**

# Ontario Apprenticeship Training Tax Credit

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2015-12-31 |

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

| 110 Name of person to contact for more information | 120 Telephone number |
|---|---|
| GLENDY CHEUNG | (416) 345-6812 |

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

## Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * . . . . . . . . . . . . . . . . . . . . . . **300** 100,000

**For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:**

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[ 10\% \times \frac{(\text{amount on line 300} \text{ minus } 400{,}000)}{200{,}000} \right]$$

**Specified percentage** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **312** 45.000 %

**For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:**

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\% - \left[ 5\% \times \frac{(\text{amount on line 300} \text{ minus } 400{,}000)}{200{,}000} \right]$$

**Specified percentage** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **314** 30.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

| | A<br>Trade code<br>400 | B<br>Apprenticeship program/trade name<br>405 | C<br>Name of apprentice<br>410 |
|---|---|---|---|
| 1. | 309a | Electrician-Construction and Maintenance | [redacted] |
| 2. | 310t | Truck And Coach Technician | [redacted] |
| 3. | 309a | Electrician-Construction and Maintenance | [redacted] |
| 4. | 434a | Powerline Technician | [redacted] |

| | D<br>Original contract or training agreement number<br>420 | E<br>Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1)<br>425 | F<br>Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2)<br>430 | G<br>End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3)<br>435 |
|---|---|---|---|---|
| 1. | [redacted] | 2013-06-03 | 2015-11-01 | 2015-11-26 |
| 2. | [redacted] | 2013-01-28 | 2015-11-01 | 2015-12-23 |
| 3. | [redacted] | 2014-05-26 | 2015-12-01 | 2015-12-31 |
| 4. | [redacted] | 2012-02-27 | 2015-11-01 | 2015-12-31 |

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

## Part 4 – Ontario apprenticeship training tax credit (continued)

| | H1<br>Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1)<br>442 | H2<br>Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1)<br>443 | I<br>Maximum credit amount for the tax year (see note 2)<br>445 |
|---|---|---|---|
| 1. | 26 | | 712 |
| 2. | 53 | | 1,452 |
| 3. | 31 | | 849 |
| 4. | 61 | | 1,671 |

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*) or ($5,000 × H2/365*), whichever applies.
* 366 days, if the tax year includes February 29

| | J1<br>Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3)<br>452 | J2<br>Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3)<br>453 | K<br>Eligible expenditures **multiplied** by specified percentage (see note 4)<br>460 |
|---|---|---|---|
| 1. | 4,798 | | 2,159 |
| 2. | 11,357 | | 5,111 |
| 3. | 4,059 | | 1,827 |
| 4. | 11,820 | | 5,319 |

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.
For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

| | L<br>ATTC on eligible expenditures (lesser of columns I and K)<br>470 | M<br>ATTC on repayment of government assistance (see note 5)<br>480 | N<br>ATTC for each apprentice (column L or M, whichever applies)<br>490 |
|---|---|---|---|
| 1. | 712 | | 712 |
| 2. | 1,452 | | 1,452 |
| 3. | 849 | | 849 |
| 4. | 1,671 | | 1,671 |

**Ontario apprenticeship training tax credit** (total of amounts in column N) 500 4,684 O

**Or**, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ______ % = . . . . . . . . . . . . . . . . ________ P

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

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# T2 Corporation Income Tax Return

055 **Do not use this area**

Filed: 2017-08-28
EB-2017-0051
Exhibit D2-09-01
Attachment 6
Page 1 of 121

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see cra.gc.ca or Guide T4012, *T2 Corporation - Income Tax Guide*.

## Identification

**Business number (BN)** . . . . . . . . . . 001 87083 6269 RC0001

**Corporation's name**
002 Hydro One Remote Communities Inc.

**Address of head office**
Has this address changed since the last time we were notified? . . . . . . . . . . . . 010 1 Yes [ ] 2 No [X]
If **yes**, complete lines 011 to 018.
011 483 BAY STREET 8TH FLOOR
012 SOUTH TOWER
City: 015 TORONTO — Province, territory, or state: 016 ON
Country (other than Canada): 017 — Postal or ZIP code: 018 M5G 2P5

**Mailing address** (if different from head office address)
Has this address changed since the last time we were notified? . . . . . . . . . . . 020 1 Yes [ ] 2 No [X]
If **yes**, complete lines 021 to 028.
021 c/o TAX DEPARTMENT
022 483 BAY STREET 7TH FLOOR
023 SOUTH TOWER
City: 025 TORONTO — Province, territory, or state: 026 ON
Country (other than Canada): 027 — Postal or ZIP code: 028 M5G 2P5

**Location of books and records** (if different from head office address)
Has this address changed since the last time we were notified? . . . . . . . . . 030 1 Yes [ ] 2 No [X]
If **yes**, complete lines 031 to 038.
031 483 BAY STREET 7TH FLOOR
032 SOUTH TOWER
City: 035 TORONTO — Province, territory, or state: 036 ON
Country (other than Canada): 037 — Postal or ZIP code: 038 M5G 2P5

040 **Type of corporation at the end of the tax year** (tick one)
- [ ] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [X] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . . . . . . . . . . 043 Year Month Day

**To which tax year does this return apply?**
Tax year start (Year Month Day): 060 2016-01-01
Tax year-end (Year Month Day): 061 2016-12-31

**Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060?** . . . . . . . . . . . . . 063 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired . . . . . . . . . . . . . 065 Year Month Day

**Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)?** . . . . . . . . . . . 066 1 Yes [ ] 2 No [X]

**Is the corporation a professional corporation that is a member of a partnership?** . . . . . . . . . . . . . . . . 067 1 Yes [ ] 2 No [X]

**Is this the first year of filing after:**
Incorporation? . . . . . . . . . . . . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . . . . . . . . . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . 076 1 Yes [ ] 2 No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . . 078 1 Yes [ ] 2 No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . 079

**Is the corporation a resident of Canada?** 080 1 Yes [X] 2 No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 3 Exempt under paragraph 149(1)(t)
- [ ] 4 Exempt under other paragraphs of section 149

**Do not use this area**
095 096 898

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| Is the corporation an associated CCPC? | 160 | | 23 |
| Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders who own voting shares? | 151 | | 19 |
| Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | X | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | X | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership account number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation own any shares in one or more foreign affiliates in the tax year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*? | 170 | X | 29 |
| Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | |
| Does the corporation earn income from one or more Internet webpages or websites? | 180 | X | 88 |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine? | 202 | | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | | 3 |
| Is the corporation claiming any type of losses? | 204 | X | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | X | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | | 6 |
| i) Is the corporation claiming the small business deduction and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), or f) business limit assigned under subsection 125(3.2); or ii) does the corporation have aggregate investment income at line 440? | 207 | | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any property that is eligible capital property? | 210 | X | 10 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)? | 213 | X | 13 |
| Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits? | 221 | | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | | 31 |
| Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | X | 33/34/35 |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | X | |
| Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II - Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit refund? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit refund? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments (continued)

| | Line | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates in the tax year? | 271 | | T1134 |
| Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | 262 | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| | Line | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | | X |
| Is the corporation inactive? | 280 | | X |

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

| Line | Product or service | Line | % |
|---|---|---|---|
| 284 | Electricity generation and distribution | 285 | 100.000 % |
| 286 | | 287 | % |
| 288 | | 289 | % |

| | Line | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | | X |
| Did the corporation emigrate from Canada during the tax year? | 292 | | X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | | |

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

## Taxable income

| | Line | | Amount | |
|---|---|---|---|---|
| Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. | 300 | | -404,460 | A |
| **Deduct:** | | | | |
| Charitable donations from Schedule 2 | 311 | | | |
| Cultural gifts from Schedule 2 | 313 | | | |
| Ecological gifts from Schedule 2 | 314 | | | |
| Gifts of medicine from Schedule 2 | 315 | | | |
| Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | | | |
| Part VI.1 tax deduction* | 325 | | | |
| Non-capital losses of previous tax years from Schedule 4 | 331 | | | |
| Net capital losses of previous tax years from Schedule 4 | 332 | | | |
| Restricted farm losses of previous tax years from Schedule 4 | 333 | | | |
| Farm losses of previous tax years from Schedule 4 | 334 | | | |
| Limited partnership losses of previous tax years from Schedule 4 | 335 | | | |
| Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | |
| Prospector's and grubstaker's shares | 350 | | | |
| Subtotal | | | | B |
| Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | | C |
| Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | 355 | | | D |
| **Taxable income** (amount C **plus** amount D) | 360 | | | |
| Income exempt under paragraph 149(1)(t) | 370 | | | |
| **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | | Z |
| **Taxable income** for the year from a personal services business** | | | | Z.1 |

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

** For a taxation year that ends after 2015.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

Income from active business carried on in Canada from Schedule 7 . . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . . **410** ______ C

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction:**

Amount C ______ x **415** *** ______ D / 11,250 = . . . . . ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** ______ F

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . . ______ G

Amount F **minus** amount G . . . . . **427** ______ H

**Small business deduction**

Amount A, B, C, or H, whichever is the least ______ x Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366 x 17 % = ______ 1

Amount A, B, C, or H, whichever is the least ______ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 17.5 % = ______ 2

Total of amounts 1 and 2 (enter amount I on line J on page 8) **430** ______ I

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**Specified corporate income and assignment under subsection 125(3.2)**

**Applicable to tax years that begin after March 21, 2016**

Except that, if the tax year of your corporation started before **and** ends on or after March 22, 2016 and in the tax year of a CCPC, you can make an assignment of business limit to that other CCPC if its tax year started after March 21, 2016.

| | J1<br>Name of corporation receiving the income and assigned amount | J<br>Business number of the corporation receiving the assigned amount<br>**490** | K<br>Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column J [3]<br>**500** | L<br>Business limit assigned to corporation identified in column J [4]<br>**505** |
|---|---|---|---|---|
| 1. | | | | |
| | | | Total **510** ______ | Total **515** ______ |

**Notes:**

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
(A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
(B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
(I) persons (other than the private corporation) with which the corporation deals at arm's length, or
(II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column K in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 425.

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | A |
| Lesser of amounts B9 and H9 from Part 9 of Schedule 27 | | | B | |
| Amount K13 from Part 13 of Schedule 27 | | | C | |
| Personal services business income | 432 | | D | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | | E | |
| Amount from line 400, 405, 410, or 427 on page 4, whichever is the least | | | F | |
| Aggregate investment income from line 440 on page 6* | | | G | |
| Subtotal (**add** amounts B to G) | | | | H |
| Amount A **minus** amount H (if negative, enter "0") | | | | I |
| **General tax reduction for Canadian-controlled private corporations** – Amount I **multiplied** by 13 % | | | | J |

Enter amount J on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | K |
| Lesser of amounts B9 and H9 from Part 9 of Schedule 27 | | | L | |
| Amount K13 from Part 13 of Schedule 27 | | | M | |
| Personal services business income | 434 | | N | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | | O | |
| Subtotal (**add** amounts L to O) | | | | P |
| Amount K **minus** amount P (if negative, enter "0") | | | | Q |
| **General tax reduction** – Amount Q **multiplied** by 13 % | | | | R |

Enter amount R on line 639 on page 8.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

Aggregate investment income from Schedule 7 . . . **440** ______ A

Amount A ______ x (Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366) x 26 2/3 % = ______ 1

Amount A ______ x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 30 2/3 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ ______ B

Foreign investment income from Schedule 7 . . . **445** ______ C

Amount C ______ x (Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366) x 9 1/3 % = ______ 3

Amount C ______ x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 8 % = ______ 4

Subtotal (amount 3 **plus** amount 4) ______ D

Foreign non-business income tax credit from line 632 on page 8 **minus** amount D (if negative, enter "0") . . . ______ E

Amount B **minus** amount E (if negative, enter "0") . . . ______ F

Foreign non-business income tax credit from line 632 on page 8 . . . ______ G

(Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366) x 35 = . . . ______ 5

(Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 38 2/3 = . . . 38.66667 6

Subtotal (amount 5 **plus** amount 6) 38.6667 H

Amount G ______ x 100 / H = 100 / 38.6667 = . . . ______ I

Taxable income from line 360 on page 3 . . . ______ J

**Deduct:**

Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . ______ K

Amount I . . . ______ L

Foreign business income tax credit from line 636 on page 8 . . . ______ x 4 = ______ M

Subtotal (total of amounts K to M) ______ ► ______ N

Subtotal (amount J **minus** amount N) ______ O

Amount O ______ x (Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366) x 26 2/3 % = ______ 7

Amount O ______ x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 30 2/3 % = ______ 8

Subtotal (amount 7 **plus** amount 8) ______ ______ P

Part I tax payable **minus** investment tax credit refund (line 700 **minus** line 780 from page 9) . . . ______ Q

**Refundable portion of Part I tax** – Amount F, P, or Q, whichever is the least . . . **450** ______ R

## Refundable dividend tax on hand

| | | | | |
|---|---|---|---|---|
| Refundable dividend tax on hand at the end of the previous tax year | 460 | | | |
| **Deduct:** | | | | |
| Dividend refund for the previous tax year | 465 | | | |
| | | | | A |
| **Add**: | | | | |
| Refundable portion of Part I tax from line 450 on page 6 | | | B | |
| Total Part IV tax payable from Schedule 3 | | | C | |
| Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation | 480 | | | |
| Subtotal (add amounts B, C, and line 480) | | | | D |
| **Refundable dividend tax on hand at the end of the tax year** – Amount A **plus** amount D | 485 | | | |

## Dividend refund

**Private and subject corporations at the time taxable dividends were paid in the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 | | | E | |
| Amount E ___ x Number of days in the tax year before January 1, 2016 ___ / Number of days in the tax year 366 x 33 1/3 % = | | | 1 | |
| Amount E ___ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 38 1/3 % = | | | 2 | |
| Subtotal (amount 1 **plus** amount 2) | | ► | | F |
| Refundable dividend tax on hand at the end of the tax year from line 485 above | | | | G |
| **Dividend refund** – Amount F or G, whichever is less | | | | H |

Enter amount H on line 784 on page 9.

## Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % . . . **550** ______ A

**Additional tax on personal services business income** (section 123.5)

Taxable income from a personal services business **555** ______ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 5 % = **560** ______ B

Recapture of investment tax credit from Schedule 31 . . . **602** ______ C

**Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income**
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . ______ D

Taxable income from line 360 on page 3 . . . ______ E

**Deduct:**
Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . ______ F

Net amount (amount E **minus** amount F) ______ ▶ ______ G

Amount D or G, whichever is less ______ x Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366 x 6 2 / 3 % = ______ 1

Amount D or G, whichever is less ______ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 10 2 / 3 % = ______ 2

Refundable tax on CCPC's investment income (amount 1 **plus** amount 2) . . . **604** ______ ______ H

Subtotal (**add** amounts A, B, C, and H) ______ I

**Deduct:**

Small business deduction from line 430 on page 4 . . . ______ J

Federal tax abatement . . . **608** ______

Manufacturing and processing profits deduction from Schedule 27 . . . **616** ______

Investment corporation deduction . . . **620** ______

Taxed capital gains **624** ______

Additional deduction – credit unions from Schedule 17 . . . **628** ______

Federal foreign non-business income tax credit from Schedule 21 . . . **632** ______

Federal foreign business income tax credit from Schedule 21 . . . **636** ______

General tax reduction for CCPCs from amount J on page 5 . . . **638** ______

General tax reduction from amount R on page 5 . . . **639** ______

Federal logging tax credit from Schedule 21 . . . **640** ______

Eligible Canadian bank deduction under section 125.21 . . . **641** ______

Federal qualifying environmental trust tax credit . . . **648** ______

Investment tax credit from Schedule 31 . . . **652** ______

Subtotal ______ ______ K

**Part I tax payable** – Amount I **minus** amount K . . . ______ L

Enter amount L on line 700 on page 9.

## Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source cra.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html, personal information bank CRA PPU 047.

## Summary of tax and credits

**Federal tax**

| | | |
|---|---|---|
| Part I tax payable from amount L on page 8 | 700 | |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | | |
|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | |
| Total tax payable | 770 | A |

**Deduct other credits:**

| | | | |
|---|---|---|---|
| Investment tax credit refund from Schedule 31 | 780 | | |
| Dividend refund from amount H on page 7 | 784 | | |
| Federal capital gains refund from Schedule 18 | 788 | | |
| Federal qualifying environmental trust tax credit refund | 792 | | |
| Canadian film or video production tax credit refund (Form T1131) | 796 | | |
| Film or video production services tax credit refund (Form T1177) | 797 | | |
| Tax withheld at source | 800 | | |
| Total payments on which tax has been withheld 801 | | | |
| Provincial and territorial capital gains refund from Schedule 18 | 808 | | |
| Provincial and territorial refundable tax credits from Schedule 5 | 812 | 29,233 | |
| Tax instalments paid | 840 | 372,676 | |
| Total credits | 890 | 401,909 | 401,909 B |

Refund code 894 2 Overpayment 401,909

Balance (amount A **minus** amount B) -401,909

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . .

For information on how to make your payment, go to cra.gc.ca/payments.

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number

918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

## Certification

I, 950 LOPEZ (Last name) 951 CHRIS (First name) 954 SVP, Finance (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2017-06-26 — Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (416) 345-4575 — Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No X

958 GLENDY CHEUNG — Name of other authorized person

959 (416) 345-6812 — Telephone number

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

# Schedule of Instalment Remittances

Name of corporation contact: Glendy Cheung

Telephone number: (416) 345-6812

| Effective interest date | Description (instalment remittance, split payment, assessed credit) | Amount of credit |
|---|---|---|
| 2016-01-28 | Instalments | 30,000 |
| 2016-02-26 | Instalments | 30,000 |
| 2016-03-31 | Instalments | 30,000 |
| 2016-04-29 | Instalments | 30,000 |
| 2016-05-31 | Instalments | 30,000 |
| 2016-07-29 | Instalments | 60,000 |
| 2016-08-31 | Instalments | 30,000 |
| 2016-09-30 | Instalments | 30,000 |
| 2016-10-31 | Instalments | 30,000 |
| 2016-11-30 | Instalments | 30,000 |
| 2016-12-30 | Instalments | 30,000 |
| 2016-02-26 | Transfer from 2015-12-31 | 13,906 |
| 2016-01-28 | Total transfer to prior years | -1,230 |
| | **Total amount of instalments claimed (carry the result to line 840 of the T2 Return)** | 372,676 **A** |
| | **Total instalments credited to the taxation year per T9** | 372,676 **B** |

## Transfer

| | Account number | Taxation year end | Amount | Effective interest date | Description |
|---|---|---|---|---|---|
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |

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**SCHEDULE 100**

Form identifier 100

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

## Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 16,932,000 | 9,110,000 |
| | Total tangible capital assets | 2008 | + | 70,256,000 | 68,463,000 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 26,630,000 | 25,793,000 |
| | Total intangible capital assets | 2178 | + | | |
| | Total accumulated amortization of intangible capital assets | 2179 | – | | |
| | Total long-term assets | 2589 | + | 43,845,000 | 19,766,000 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 104,403,000 | 71,546,000 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 7,972,291 | 12,111,000 |
| | Total long-term liabilities | 3450 | + | 96,352,000 | 59,890,000 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 104,324,291 | 72,001,000 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | 78,709 | -455,000 |
| | **Total liabilities and shareholder equity** | 3640 | = | 104,403,000 | 71,546,000 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | -4,393,291 | -4,913,000 |

* Generic item

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**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Income statement information** | | | | |
| | Total sales of goods and services | 8089 | + | 50,357,000 | 7,646,000 |
| | Cost of sales | 8518 | – | 23,669,000 | 4,265,000 |
| | **Gross profit/loss** | 8519 | = | 26,688,000 | 3,381,000 |
| | Cost of sales | 8518 | + | 23,669,000 | 4,265,000 |
| | Total operating expenses | 9367 | + | 26,241,291 | 2,911,000 |
| | **Total expenses** (mandatory field) | 9368 | = | 49,910,291 | 7,176,000 |
| | Total revenue (mandatory field) | 8299 | + | 50,357,000 | 7,646,000 |
| | Total expenses (mandatory field) | 9368 | – | 49,910,291 | 7,176,000 |
| | **Net non-farming income** | 9369 | = | 446,709 | 470,000 |
| | **Farming income statement information** | | | | |
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | 446,709 | 470,000 |
| | **Total other comprehensive income** | 9998 | = | 14,000 | 2,000 |
| | **Extraordinary items and income (linked to Schedule 140)** | | | | |
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | -73,000 | 383,000 |
| | Future (deferred) income tax provision | 9995 | – | | |
| | Total – Other comprehensive income | 9998 | + | 14,000 | 2,000 |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 533,709 | 89,000 |

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**Schedule 141**

# Notes Checklist

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012*, T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [X] 2 No [ ]

**Note**
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

- Completed an auditor's report . . . . . 1 [ ]
- Completed a review engagement report . . . . . 2 [ ]
- Conducted a compilation engagement . . . . . 3 [ ]

## Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [ ]

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: . . . . . **110**

- Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]
- Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

- Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [X]
- Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [X] 2 No [ ]
- Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [X] 2 No [ ]
- Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income Increase (decrease) | | In OCI Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

# T2 BAR CODE RETURN

**Name: Hydro One Remote Communities Inc.**

**BN: 87083 6269 RC 0001**
**Tax Year Start: 2016-01-01**
**Tax Year End: 2016-12-31**

S.13(7.4) Election

Taxpayer is electing under subsection 13(7.4) of the Income Tax Act with respect to amounts that would normally be included in income under paragraph 12(1)(x). The amount elected to reduce the cost of depreciable property instead of being included in income is $3,373,446.

Financial Statement Notes

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and was wholly owned by the Province of Ontario (the Province) until October 31, 2015. On October 31, 2015, Hydro One Limited, a wholly owned subsidiary of the Province, acquired all issued and outstanding shares of Hydro One from the Province. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the Business Corporations Act (Ontario) and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. The Company uses a cost recovery model applied to achieve breakeven net income and the Financial Statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2016 have been prepared and are publicly available.

For the year ended December 31, 2015, the Company has reported a net loss due to recognition of tax expense resulting from the Company no longer being exempt from tax under the Federal Tax Regime. This tax is not recovered from ratepayers as it is funded by the Company's shareholder, and therefore, it is not included in the cost recovery model applied to achieve breakeven net income. See note 6 - Income Taxes.

Hydro One Remote Communities performed an evaluation of subsequent events through to April 27, 2017, 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. No such events or transactions were identified.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

On March 17, 2016, the OEB approved an increase of 2.10% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2016.

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 include its regulatory assets and liabilities in 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 would be reflected in results of operations in the period that the assessment is made.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

The departure tax recovery is not recoverable from ratepayers and therefore is not included in the cost recovery model applied to achieve breakeven net income.

Revenue Recognition

Revenues attributable to the generation and 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. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

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

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are 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 billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed 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 allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Long-term accounts receivable are recorded at their invoiced amount and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. Provision for uncollectible amounts for this component is set at the inception of the balance and is maintained until settlement of those amounts. The provision for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

Income Taxes

On October 31, 2015, the Company ceased to be exempt from tax under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) (Federal Tax Regime). Prior to that date, Hydro One Remote Communities was required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the Electricity Act, 1998 (Ontario) (PILs Regime). These payments were 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. Upon exiting the PILs Regime, Hydro One Remote

Communities 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 Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it 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 Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are 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 Statements of Operations and Comprehensive Income (Loss).

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.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter

-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash 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%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. 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 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, 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 generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

Generation

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

Distribution

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

Administration and Service

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

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. 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 Statements of Operations and Comprehensive Income (Loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction in Progress

Construction 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

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 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 |
| Generation | 20 years | 3% - 7% | 5% |

| | | | |
|---|---|---|---|
| Distribution | 46 years | 1% - 7% | 2% |
| Administration and service | 36 years | 3% - 20% | 4% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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.

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 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.

The carrying costs of most of Hydro One Remote Communities' 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. As at December 31, 2016 and 2015, no asset impairment had been recorded.

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 net of related debt on the Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income (Loss). 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. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents net income and OCI in a single continuous Statement of Operations and Comprehensive Income (Loss).

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 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.

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 11 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2016 and 2015. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's 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 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 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, 2016, the measurement date for all plans was December 31.

Pension Benefits

Hydro One has a contributory defined benefit pension plan (Pension Plan) covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the Pension Plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Statements of Operations and Comprehensive Income (Loss).

A detailed description of Hydro One pension plans is provided in note 18 - Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2016.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's 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 accumulated OCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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 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 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.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in note 18 - Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2016.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited's 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. Forfeitures are recognized as they occur (see note 3).

Long-term Incentive Plan (LTIP)

The Company measures its LTIP at fair value based on the grant date share price of Hydro One Limited's common shares. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its 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 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 Remote Communities records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) 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 Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

# T2 BAR CODE RETURN

**Name: Hydro One Remote Communities Inc.**

**BN: 87083 6269 RC 0001**
**Tax Year Start: 2016-01-01**
**Tax Year End: 2016-12-31**

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One Remote Communities:

Recently Adopted Accounting Guidance

ASU Date issued Description Effective date Impact on Hydro One

2015-01 January
2015 Extraordinary items are no longer required to be presented separately in the income statement.
January 1, 2016 No material impact upon adoption
2015-03 April 2015 Debt issuance costs are required to be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums. January 1, 2016 Reclassification of deferred debt issuance costs and net unamortized debt premiums as an offset to long-term debt. Applied retrospectively (see note 10).

2015-05 April 2015 Cloud computing arrangements that have been assessed to contain a software licence should be accounted for as internal-use software.
January 1, 2016 No material impact upon adoption
2015-17 November 2015 All deferred tax assets and liabilities are required to be classified as noncurrent on the balance sheet.
January 1, 2017 This ASU was early adopted as of April 1, 2016 and

was applied prospectively. As a result, the current portions of the Company's deferred income tax assets are reclassified as noncurrent assets on the Balance Sheet. Prior periods were not retrospectively adjusted (see note 6).

2016-09 March 2016 Several aspects of the accounting for stock-based payment transactions were simplified, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.

January 1, 2017 This ASU was early adopted as of October 1, 2016 and was applied retrospectively. As a result, the Company accounts for forfeitures as they occur. There were no other material impacts upon adoption.

Recently Issued Accounting Guidance Not Yet Adopted

ASU Date issued Description Effective date Anticipated impact on Hydro One

2014-09

2015-14 2016-08 2016-10 2016-12

2016-20 May 2014 - December 2016 ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard.

January 1, 2018 Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is now underway and will continue through to the third quarter of 2017, with the end result being a determination of the financial impact of this standard. The Company is on track for implementation of this standard by the effective date.

2016-02 February 2016 Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.
January 1, 2019 An initial assessment is currently underway encompassing a review of all existing leases, which will be followed by a detailed review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

2016-13 June 2016 The amendment provides users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date.
January 1, 2019 Under assessment
2016-15 August 2016 The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.
January 1, 2018 Under assessment
2016-18 November 2016 The amendment requires that restricted cash or restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning and end-of-period balances in the statement of cash

flows.

January 1, 2018 Under assessment

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (thousands of dollars) 2016 2015

Depreciation of property, plant and equipment 2,751 2,711

Asset removal costs 620 968

Amortization of regulatory assets 1,247 1,223

4,618 4,902

5. FINANCING CHARGES

Year ended December 31 (thousands of dollars) 2016 2015

Interest on long-term debt 1,915 1,655

Interest expense (income) on inter-company demand facility (48)

65

Amortization of hedging losses 14 14

Other 31 41

Interest capitalized on construction in progress (115) (97)

1,797 1,678

6. 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 (thousands of dollars) 2016 2015

Income taxes / provision for PILs at statutory rate 118 166

Increase (decrease) resulting from:

Net temporary differences recoverable in future rates charged to customers:

Depreciation and amortization in excess of capital cost allowance
364 1,112

RRPR variance account 296 482

Post-retirement and post-employment benefit expense in excess of cash
payments 223 201

Losses carryforward - (870)

Change in valuation allowance (516)
) -

Environmental expenditures (330) (324)

Overheads capitalized for accounting but deducted for tax purposes
(104) (141)

Pension contribution in excess of pension expense (76) (119)

Interest capitalized for accounting but deducted for tax purposes
(31) (26)

Other (27) 72

Net temporary differences (201) 387

Net tax expense resulting from transition from PILs Regime to Federal Tax
Regime - expenditures 5,000

Prior year adjustments (15) (3)

Other permanent differences 25 (9)

Total income taxes / provision for PILs (73) 5,541

The major components of income tax expense (recovery) are as follows:

Year ended December 31 (thousands of dollars) 2016 2015

Current income taxes / provision for (recovery of) PILs (73)

5,541

Deferred income taxes / provision for PILs - -

Total income taxes / provision for (recovery of) PILs (73) 5,541

Effective income tax rate (16.2%) 882%

The provision for PILs / current income taxes is remitted to, or received
from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime), respectively.
At December 31, 2016, the Company had $463 thousand receivable from the CRA
(2015 - $37 thousand payable to the CRA) and $nil receivable from the OEFC
(2015 - $327 thousand).

On October 31, 2015, the Company's exemption from tax under the Federal Tax
Regime ceased to apply. Under the PILs Regime, the Company 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 Remote Communities making
payments in lieu of tax (Departure Tax) totaling $5 million. To enable Hydro
One Remote Communities to make the Departure Tax payment, Hydro One subscribed
for 64 common shares of Hydro One Remote Communities for $5 million. The
Company used the proceeds of this share subscription to pay the Departure Tax.

For the year ended December 31, 2016, the Company reported net income due to recognition of departure tax recovery. The following table presents a reconciliation of net income (loss) to net income under the cost recovery model to achieve breakeven net income:

Year ended December 31 (thousands of dollars) 2016 2015

Net income before income taxes 447 628

Income taxes under cost-recovery model 447 628

Net income under cost-recovery model - -

Tax expense - Departure Tax - 5,000

Tax recovery (520) (87)

Net income (loss) 520 (4,913)

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, 2016 and 2015, deferred income tax assets and liabilities consisted of the following items:

December 31 (thousands of dollars) 2016 2015

Deferred income tax assets (liabilities)

Post-retirement and post-employment benefits expense in excess of cash payments 5,440 5,038

Environmental expenditures 12,924 3,984

Depreciation and amortization in excess of capital cost allowance

6,617 7,548

Regulatory amounts not recognized for tax 1,845 2,263

(14,358)

(5,803)

Other (299) (215)

10,324 10,552

Less: Valuation allowance (6,106) (6,622)

Total deferred income tax assets 4,218 3,930

Less: current portion - 125

4,218 3,805

During 2016 and 2015, there was no change in the rate applicable to deferred tax assets and liabilities. The valuation allowance for deferred tax assets as at December 31, 2016 was $6,106 thousand (2015 - $6,622 thousand). The valuation allowance primarily relates to temporary differences for non-depreciable assets. As at December 31, 2016, the Company has non-capital losses of $55 thousand, which would expire in 2036.

7. ACCOUNTS RECEIVABLE

December 31, 2016 (thousands of dollars) Current accounts receivable Long-term accounts receivable

Total

Accounts receivable - billed 3,396 702 4,098

| | | | |
|---|---|---|---|
| Accounts receivable - unbilled | 2,302 | - | 2,302 |
| Accounts receivable, gross | 5,698 | 702 | 6,400 |
| Allowance for doubtful accounts | (141) | (57) | (198) |
| Accounts receivable, net | 5,557 | 645 | 6,202 |

| December 31, 2015 (thousands of dollars) | Current accounts receivable | Long-term accounts receivable | Total |
|---|---|---|---|
| Accounts receivable - billed | 3,514 | 1,181 | 4,695 |
| Accounts receivable - unbilled | 1,077 | - | 1,077 |
| Accounts receivable, gross | 4,591 | 1,181 | 5,772 |
| Allowance for doubtful accounts | (156) | (111) | (267) |
| Accounts receivable, net | 4,435 | 1,070 | 5,505 |

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2016 and 2015:

| December 31 (thousands of dollars) | 2016 | 2015 |
|---|---|---|
| Allowance for doubtful accounts - January 1 | (267) | (304) |

Write-offs 69 67

Adjustments to allowance for doubtful accounts - (30)

Allowance for doubtful accounts - December 31 (198) (267)

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2016 (thousands of dollars) Property, Plant

and Equipment1 Accumulated Depreciation Construction

in Progress

Total

Generation 46,508 21,492 181 25,197

Distribution 10,542 2,234 476 8,784

Administration and service 12,496 2,904 53 9,645

69,546 26,630 710 43,626

1 Includes future use assets totalling $2,013 thousand.

December 31, 2015 (thousands of dollars) Property, Plant

and Equipment1 Accumulated Depreciation Construction

in Progress

Total

Generation 45,779 21,150 2,966 20,330

826 20,330

96 25,455 20,330

Distribution 9,780 2,049 312 8,043

Administration and service 11,716 2,594 50 9,172

67,275 25,793 1,188 42,670

1 Includes future use assets totalling $1,902 thousand.

Financing charges capitalized on property, plant and equipment under construction were $115 thousand in 2016 (2015 - $97 thousand).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

December 31 (thousands of dollars) 2016 2015

Regulatory assets:

Environmental 35,845

11,051

RRPR variance account 1,644 2,760

Post-retirement and post-employment benefits 2,334 2,285

Stock-based compensation 318 99

Total regulatory assets 40,141

16,195

Less: current portion 1,183

1,483

38,958

14,712

Regulatory liabilities:

| | | |
|---|---|---|
| Deferred income tax regulatory liability | 4,218 | 3,930 |
| Total regulatory liabilities | 4,218 | 3,930 |
| Less: current portion | - | 125 |
| | 4,218 | 3,805 |

Environmental

The Company 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 2016, the environmental regulatory asset increased by $25,732 thousand (2015 - decreased by $448 thousand) to reflect related changes in the Company's environmental liabilities. 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 Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2016 operation, maintenance and administration expenses would have been higher by $25,732 thousand (2015 - lower by $448 thousand). In addition, 2016 amortization expense would have been lower by $1,247 thousand (2015 - $1,222 thousand), and 2016 financing charges would have been higher by $309 thousand (2015 - $352 thousand).

RRPR Variance Account

Hydro One Remote Communities receives RRRP amounts from the IESO. At December

31, 2016, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of cumulative RRRP amounts received. In 2016, RRRP amounts received were higher than amounts required to achieve breakeven net income, and as such, the regulatory asset was reduced by $1,116 thousand (2015 - $1,818 thousand). In the absence of rate-regulated accounting, 2016 revenue would have been higher by $1,116 thousand (2015 - $1,818 thousand).

Post-Retirement and Post-Employment Benefits

The Company 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, 2016 OCI would have been lower by $49 thousand (2015 - higher by $352 thousand).

Stock-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2016 operation, maintenance and administration expenses would have been higher by $156 thousand (2015 - $69 thousand).

Deferred Income Tax Regulatory 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 2016 income tax expense would have been higher by approximately $201 thousand (2015 - lower by $387 thousand).

10. LONG-TERM DEBT

The following table presents outstanding long-term debt at December 31, 2016 and 2015:

| December 31 (thousands of dollars) | 2016 | 2015 |
|---|---|---|
| 3.02% note due 20261 | 10,000 | - |
| 5.38% note due 2036 | 23,000 | 23,000 |
| 4.19% note due 2044 | 10,000 | 10,000 |
| | 43,000 | 33,000 |
| Less: Deferred debt issuance costs2 | (179) | (144) |
| Less: Net unamortized debt premiums2 | (38) | (35) |

Long-term debt 42,783 32,821

1 On February 24, 2016, Hydro One Remote Communities issued a $10 million note with a maturity date of February 24, 2026 and a coupon rate of 3.02%. The note is payable to Hydro One.

2 Effective January 1, 2016, deferred debt issuance costs and net unamortized debt discounts were reclassified from other long-term assets as an offset to long-term debt upon adoption of ASU 2015-03 (see note 3). Balances as at December 31, 2015 were updated to reflect the retrospective adoption of ASU 2015-03.

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 (thousands of dollars) | Weighted Average Interest Rate (%) |
|---|---|---|
| 1 - 5 years | - | - |
| 6 - 10 years | 10,000 | 3.0 |
| Over 10 years | 33,000 | 5.0 |
| | 43,000 | 4.6 |

Interest payment obligations related to long-term debt are summarized by year in the following table:

| Year | Interest Payments (thousands of dollars) |
|---|---|
| 2017 | 1,958 |
| 2018 | 1,958 |
| 2019 | 1,958 |
| 2020 | 1,958 |
| 2021 | 1,958 |
| | 9,790 |
| 2022-2026 | 9,642 |
| 2027+ | 19,089 |
| | 38,521 |

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.

Hydro One Remote Communities 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 Remote Communities 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, 2016 and 2015, the Company's 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 Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2016 and 2015 is as follows:

December 31, 2016 (thousands of dollars) Carrying

Value Fair

Value

Level 1

Level 2

Level 3

Assets:

Inter-company demand facility 7,253 7,253 7,253 - -

7,253 7,253 7,253 - -

Liabilities:

Long-term debt 42,783 48,588 - 48,588 -

42,783 48,588 - 48,588 -

December 31, 2015 (thousands of dollars) Carrying

Value Fair

Value

Level 1

Level 2

Level 3

Liabilities:

Inter-company demand facility 6,056 6,056 6,056 - -

Long-term debt 32,821 37,957 - 37,957 -

38,877 44,013 6,056 37,957 -

The fair value 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, 2016 and 2015.

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 related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2016 and 2015, 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 Remote Communities did not earn a significant amount of revenue from any single customer. At December 31, 2016 and 2015, there was no significant accounts receivable balance due from any single customer.

At December 31, 2016, the Company's provision for bad debts was $197 thousand (2015 - $267 thousand). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2016, approximately 40% (2015 - 44%) of the Company's net accounts receivable were aged more than 60 days. The Company's 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. Hydro One Remote Communities 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, 2016, accounts payable and accrued liabilities in the amount of $7,626 thousand (2015 - $5,721 thousand) are expected to be settled in cash at their carrying amounts within the next 12 months.

12. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplementary pension plan, and post-retirement and post-employment benefit plans.

Defined Contribution Pension Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan is mandatory and covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

The Company's contributions to the DC Plan for the year ended December 31, 2016 were $8 thousand (2015 - $nil). At December 31, 2016, Company contributions payable included in accrued liabilities on the Balance Sheets were less than $1 thousand (2015 - $nil).

Defined Benefit Pension Plan

The Pension Plan is a defined benefit contributory plan which covers all regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for 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. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2016 of $108 million (2015 - $177 million) were based on an actuarial valuation effective December 31, 2015 (2015 - based on an actuarial valuation effective December 31, 2013) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2017 and 2018 are approximately $105 million and $102 million, respectively, based on the actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings. Future minimum contributions beyond 2018 will be based on an actuarial valuation effective no later than December 31, 2018. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Hydro One Supplemental Pension Plan (Supplemental 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 Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Balance Sheets.

At December 31, 2016, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,774 million (2015 - $7,683 million). The fair value of pension plan assets available for these benefits was $6,874 million (2015 - $6,731 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2016, Hydro One Remote Communities charged $866 thousand (2015 - $759 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $347 thousand (2015 - $325 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2016 were $63 thousand (2015 - $51 thousand). In addition, the incremental offset to increase the associated post-retirement and post-employment benefits regulatory assets by $49 thousand (2015 - $351 thousand decrease) was recorded on the Company's Balance Sheets to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

| December 31 (thousands of dollars) | 2016 | 2015 |
|---|---|---|
| Accrued liabilities | 400 | 373 |
| Post-retirement and post-employment benefit liability | 14,689 | 13,517 |
| | 15,089 | 13,890 |

13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2016 and 2015:

| Year ended December 31 (thousands of dollars) | 2016 | 2015 |
|---|---|---|
| Environmental liabilities, January 1 | 11,051 | 12,369 |
| Interest accretion | 309 | 352 |
| Expenditures | (1,247) | (1,222) |
| Revaluation adjustment | 25,732 | (448) |
| Environmental liabilities, December 31 | 35,845 | 11,051 |
| Less: current portion | 1,183 | 1,483 |
| | 34,662 | 9,568 |

The following table shows 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 (thousands of dollars) 2016 2015

Undiscounted environmental liabilities 37,286

11,474

Less: discounting accumulated liabilities to present value

1,441

422

Discounted environmental liabilities 35,845

11,051

At December 31, 2016, the estimated future environmental expenditures were as follows:

(thousands of dollars)

2017 1,183

2018 1,073

2019 1,794

2020 3,628

2021 3,203

Thereafter 26,405

37,286

The Company records a liability for the estimated future expenditures for the contaminated LAR 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 3.6%, 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.

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $37,286 thousand (2015 - $11,474 thousand). These expenditures are expected to be incurred over the period from 2017 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2016 to increase the LAR environmental liability by $25,732 thousand (2015 - decrease of $448 thousand).

14. SHARE CAPITAL

Common Shares

The Company has 267 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

The following table presents the movement in common shares during the year ended December 31, 2015. There was no movement in common shares during the year ended December 31, 2016.

| | |
|---|---|
| (number of common shares) | |
| Number of common shares - January 1, 2015 | 2 |
| Share split (a) | 200 |
| Common shares issued (b) | 64 |
| Common shares issued (c) | 1 |
| Number of common shares - December 31, 2015 | 267 |

(a) On November 2, 2015, all of the issued and outstanding common shares of Hydro Once Remote Communities were changed into 202 issued and outstanding common shares of the Company.

(b) On November 4, 2015, Hydro One Remote Communities issued 64 common shares to Hydro One for proceeds of $5 million.

(c) On November 3, 2015, Hydro One Remote Communities declared a stock dividend on its common shares, which due to the number of shares issued and the resulting effect on the price per share was treated as a stock split. On November 5, 2015, Hydro One Remote Communities effected a reverse split and issued as consideration one common share to Hydro One. There was no impact to the capital structure of Hydro One Remote Communities as a net result of the stock dividend and the reverse split.

Dividends

The Company does not pay dividends under its breakeven business model.

15. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited; however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Remote communities, in current and future periods.

Share Grant Plans

At December 31, 2016, Hydro One Limited had two share grant plans (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). Hydro One and

Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 plan was 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees of Hydro One Remote Communities.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The 2015 fair value of Hydro One Limited shares granted to employees of Hydro One Remote Communities was $1,091 thousand. The fair value was estimated based on the grant date Hydro One Limited 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. No shares were granted under the Share Grant Plans in 2016. Total stock-based compensation recognized during 2016 by Hydro One Remote Communities was $219 thousand (2015 - $99 thousand) and was recorded as a regulatory asset.

A summary of Hydro One Remote Communities' share grant activity under the Share Grant Plans during years ended December 31, 2016 and 2015 is presented below:

Year ended December 31, 2016 Share Grants

(Number of common shares) Weighted-Average

Price

Share grants outstanding - January 1 53,196 $20.50

Granted (non-vested) - -

Share grants forfeited (9) $20.50

Share grants transferred in1 3,455 $20.50

Share grants transferred out2 (2,921) $20.50

Share grants outstanding - December 31 53,721 $20.50

1 Share grants transferred in relate to PWU employees transferred from Hydro One Networks to Hydro One Remote Communities. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

2 Share grants transferred out relate to PWU employees transferred from Hydro One Remote Communities to Hydro One Networks. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

Year ended December 31, 2015 Share Grants

(Number of common shares) Weighted-Average

Price

Share grants outstanding - January 1 - -

Granted (non-vested) 53,196 $20.50

Share grants outstanding - December 31 53,196 $20.50

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One Limited 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 Limited. The Company matches 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. In 2016, Company contributions made under the ESOP were $19 thousand (2015 - $nil).

Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited 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 of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other stock-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

During 2016, Hydro One Limited granted awards under its LTIP to employees of Hydro One Remote Communities, consisting of PSUs and RSUs, all of which are equity settled in Hydro One Limited shares, as follows:

| Year ended December 31, 2016 | Number of PSUs | Number of RSUs |
|---|---|---|
| Units outstanding - January 1 | - | - |
| Units granted | 2,581 | 2,729 |
| Units forfeited | - | - |

Units outstanding - December 31 2,581 2,729

The grant date total fair value of the awards was $133 thousand (2015 - $nil). The compensation expense recognized by the Company relating to these awards during 2016 was $21 thousand (2015 - $nil).

16. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited, and the Province is the majority shareholder of Hydro One Limited. The IESO and OEFC are related parties to Hydro One Remote Communities because they are controlled or significantly influenced by the Province.

Year ended December 31

2016 2015

Related Party Transaction (thousands of dollars)

IESO Supply of electricity to remote northern communities - amounts received1 32,259 32,259

OEFC Departure tax payment - 5,000

Hydro One Limited and its subsidiaries Common shares issued2

- 5,000

Revenues related to the provision of services3 469 213

Costs expensed related to purchase of services3 2,965

2,973

Interest expense on long-term debt 1,915 1,655

Interest expense (income) on inter-company demand facility

(48) 65

Stock-based compensation costs 219 99

1 Consistent with the break even business model, the Company recognized $31,143 thousand as RRRP revenue in 2016 (2015 - $30,441 thousand), with the difference recorded in the regulatory asset RRPR variance account.

2 On November 4, 2015, Hydro One Remote Communities issued 64 common shares to Hydro One for proceeds of $5 million.

3 The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services.

Transactions with related parties are 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 (thousands of dollars) | 2016 | 2015 |
|---|---|---|
| Inter-company demand facility | 7,253 | (6,056) |
| Accrued interest | 280 | 172 |
| Accounts receivable | - | 95 |
| Income tax receivable | - | 327 |

17. STATEMENTS OF CASH FLOWS

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

| Year ended December 31 (thousands of dollars) | 2016 | 2015 |
|---|---|---|
| Accounts receivable | (1,122) | 19 |
| Fuel, materials and supplies | 264 | (648) |
| Income taxes receivable | (136) | 2,356 |
| Long-term accounts receivable | 425 | 180 |
| Other assets | (24) | - |
| Accounts payable | 39 | 468 |
| Accrued liabilities | 2,231 | (4,741) |
| Accrued interest | 108 | - |
| Income taxes payable | (37) | 37 |
| Post-retirement and post-employment benefit liability | 1,123 | 1,007 |
| | 2,871 | (1,322) |

| Supplementary information: | | |
|---|---|---|
| Net interest paid | 1,807 | 1,655 |
| Taxes paid | - | 5,000 |

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid are fully recovered.

18. CONTINGENCIES

Legal Proceedings

Hydro One Remote Communities 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 financial position, results of operations or cash flows.

Hydro One and three of its subsidiaries, including Hydro One Remote Communities, are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. A certification motion in the class action is pending. 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 Hydro One 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, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One 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 2016, Hydro One paid approximately $1 million (2015 - $1 million) in respect of consents obtained. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One 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 Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

19. COMMITMENTS

Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years. During the year ended December 31, 2016, the Company made lease payments totalling $120 thousand (2015 - $120 thousand). The following table presents a summary of Hydro One Remote Communities' commitments under lease agreements due in the next 5 years and thereafter.

December 31, 2016 (thousands of dollars)

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Thereafter |
|---|---|---|---|---|---|---|
| Operating lease commitments | 120 | 150 | 150 | 150 | 150 | 150 |

**SCHEDULE 100**

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

## Assets – lines 1000 to 2599

| | | | | | |
|---|---|---|---|---|---|
| 1062 | 5,557,000 | 1066 | 463,000 | 1122 | 2,476,000 |
| 1400 | 7,253,000 | 1480 | 1,183,000 | 1599 | 16,932,000 |
| 1740 | 57,050,000 | 1741 | -23,726,000 | 1900 | 12,496,000 |
| 1901 | -2,904,000 | 1920 | 710,000 | 2008 | 70,256,000 |
| 2009 | -26,630,000 | 2420 | 39,627,000 | 2421 | 4,218,000 |
| 2589 | 43,845,000 | 2599 | 104,403,000 | | |

## Liabilities – lines 2600 to 3499

| | | | | | |
|---|---|---|---|---|---|
| 2620 | 7,692,291 | 2629 | 280,000 | 3139 | 7,972,291 |
| 3140 | 42,783,000 | 3320 | 14,689,000 | 3321 | 38,880,000 |
| 3450 | 96,352,000 | 3499 | 104,324,291 | | |

## Shareholder equity – lines 3500 to 3640

| | | | | | |
|---|---|---|---|---|---|
| 3500 | 5,000,000 | 3580 | -528,000 | 3600 | -4,393,291 |
| 3620 | 78,709 | 3640 | 104,403,000 | | |

## Retained earnings – lines 3660 to 3849

| | | | | | |
|---|---|---|---|---|---|
| 3660 | -4,913,000 | 3680 | 519,709 | 3849 | -4,393,291 |

**SCHEDULE 125**

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

## Description

Sequence number . . . . . . . 0003 01

## Other comprehensive income – lines 7000 to 7020

| | |
|---|---|
| 7008 | 14,000 |

## Revenue – lines 8000 to 8299

| | | | | | |
|---|---|---|---|---|---|
| 8000 | 50,357,000 | 8089 | 50,357,000 | 8299 | 50,357,000 |

## Cost of sales – lines 8300 to 8519

| | | | | | |
|---|---|---|---|---|---|
| 8408 | 23,669,000 | 8518 | 23,669,000 | 8519 | 26,688,000 |

## Operating expenses – lines 8520 to 9369

| | | | | | |
|---|---|---|---|---|---|
| 8523 | 38,006 | 8623 | 717,246 | 8670 | 4,618,291 |
| 8714 | 1,797,000 | 9270 | 19,070,748 | 9367 | 26,241,291 |
| 9368 | 49,910,291 | 9369 | 446,709 | | |

## Extraordinary items and taxes – lines 9970 to 9999

| | | | | | |
|---|---|---|---|---|---|
| 9970 | 446,709 | 9990 | -73,000 | 9998 | 14,000 |
| 9999 | 533,709 | | | | |

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# Net Income (Loss) for Income Tax Purposes

**Schedule 1**

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

| | Line | Amount | | Total | |
|---|---|---|---|---|---|
| Amount calculated on line 9999 from Schedule 125 | | | | 533,709 | A |
| **Add:** | | | | | |
| Provision for income taxes – current | 101 | -73,000 | | | |
| Amortization of tangible assets | 104 | 4,618,291 | | | |
| Non-deductible meals and entertainment expenses | 121 | 19,003 | | | |
| Reserves from financial statements – balance at the end of the year | 126 | 13,596,022 | | | |
| Subtotal of additions | | 18,160,316 | ▶ | 18,160,316 | |

### Other additions:

| | Line | Amount |
|---|---|---|
| Debt issue expense | 208 | 1,041 |
| Financing fees deducted in books | 216 | 5,902 |

### Miscellaneous other additions:

| | 1 Description 605 | 2 Amount 295 |
|---|---|---|
| 1 | 2015 Federal apprenticeship credits | 170 |
| 2 | Non-deductible LTIP | 14,769 |
| 3 | Expenses capitalized for tax | 2,228 |
| 4 | 2015 provision to return for Ont ITC in OMA | 52,627 |
| 5 | 2016 Ontario co-op and apprentice credits accrual reversal | 9,028 |
| 6 | Regulatory Assets - Env. Liability (Opening) | 11,051,081 |
| 7 | Capital contributions received 12(1)(x) | 3,373,446 |
| | **Total** of column 2 | 14,503,349 |

| | Line | Amount | Total | |
|---|---|---|---|---|
| Total of column 2 | 296 | 14,503,349 | | |
| Subtotal of other additions | 199 | 14,510,292 | 14,510,292 | |
| **Total additions** | 500 | 32,670,608 | 32,670,608 | B |
| Amount A **plus** amount B | | | 33,204,317 | C |

### Deduct:

| | Line | Amount | | Total |
|---|---|---|---|---|
| Capital cost allowance from Schedule 8 | 403 | 4,144,708 | | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,252,422 | | |
| Other reserves on line 280 from Schedule 13 | 413 | 114,586 | | |
| Reserves from financial statements – balance at the beginning of the year | 414 | 22,181,378 | | |
| Contributions to deferred income plans from Schedule 15 | 417 | 287,313 | | |
| Subtotal of deductions | | 27,980,407 | ▶ | 27,980,407 |

### Other deductions:

### Miscellaneous other deductions:

| | 1 Description 705 | 2 Amount 395 |
|---|---|---|
| 1 | Deduction under 20(1)(e) ITA | 18,603 |
| 2 | Deductible removable costs | 87,225 |
| 3 | Deduction for capitalized amounts - see attached | 506,896 |
| 4 | Deductible OPEB costs | 395,189 |
| 5 | Environmental payments | 1,247,011 |

| | 1<br>Description<br>705 | 2<br>Amount<br>395 | | | |
|---|---|---|---|---|---|
| 6 | Capital contributions - 13(7.4) election | 3,373,446 | | | |
| | **Total** of column 2 | 5,628,370 | 396 | 5,628,370 | |
| | Subtotal of other deductions | | 499 | 5,628,370 | 5,628,370 |
| | **Total deductions** | | 510 | 33,608,777 | 33,608,777 D |

**Net income (loss) for income tax purposes** (amount C **minus** amount D) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . -404,460 E

Enter amount E on line 300 of the T2 return.

# Attached Schedule with Total

Line 208 – Debt issue expense

Title Line 208 – Debt issue expense

| Description | Operator (Note) | Amount |
|---|---|---|
| Bond Discount (761120) | | 1,041 00 |
| | **Total** | 1,041 00 |

**Note**: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

# Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

| Description | Operator (Note) | Amount | |
|---|---|---|---|
| Capitalized interest | | 115,179 | 00 |
| Capitalized overhead | + | 391,717 | 00 |
| | + | | |
| | + | | |
| | + | | |
| | **Total** | 506,896 | 00 |

**Note**: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

# Attached Schedule with Total

Line 216 – Financing fees deducted in books

Title Line 216 – Financing fees deducted in books

| Description | Operator (Note) | Amount | |
|---|---|---|---|
| Amortization underwriting fee (761780) | | 5,775 | 00 |
| Amortization of Prospectus fees (761790) | + | 127 | 00 |
| | + | | |
| | **Total** | 5,902 | 00 |

**Note**: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

# Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

| Description | Operator (Note) | Amount | |
|---|---|---|---|
| OPEB cost capitalized | | 346,853 | 00 |
| OPEB US GAAP Valuation | + | 48,336 | 00 |
| | + | | |
| | **Total** | 395,189 | 00 |

**Note**: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

# Deduction summary as per paragraph 20(1)(e) of the ITA

## Federal

### Deduction summary as per paragraph 20(1)(e) of the ITA

| Description | Date of expense | A Expense amount | B Amounts deductible in the preceding taxation years | E Annual deduction (This amount is posted to one of the lines 395 of Schedule 1) | F Balance at the end of the year |
|---|---|---|---|---|---|
| **1.** Prospectus costs - 2014 | 2014-12-31 | 1,024 | 410 | 205 | 409 |
| **2.** Prospectus costs - 2016 | 2016-12-31 | 1,738 | | 349 | 1,389 |
| **3.** Underwriting fees - 2014 | 2014-12-31 | 50,000 | 20,000 | 10,027 | 19,973 |
| **4.** Underwriting fees - 2016 | 2016-12-31 | 40,000 | | 8,022 | 31,978 |
| | **Totals** | 92,762 | 20,410 | 18,603 | 53,749 |

# Deduction as per paragraph 20(1)(e) of the ITA

This workchart allows you to determine the tax deduction as per paragraph 20(1)(e) of the Income Tax Act (ITA). It relates to the expenses of issuing or selling shares, units or interests and expenses of borrowing money.

Ensure that any of these expenses deducted in the financial statements have been added back on line 216, "Financing fees deducted in books," and/or on line 235, "Share issue expense" to Schedule 1, if applicable.

* If the check box was selected, the annual deduction will be equal to the amount in column C.

**1** Description: Prospectus costs - 2014

| Subparagraph 20(1)(e)(v) is applicable in the taxation year* | Date of expense | A<br>Expense amount | B<br>Amounts deductible in the preceding taxation years | C<br>Balance before the annual expense (column A minus column B) | D<br>20 % of amount A x number of days in the taxation year 366 / **365** | E<br>Annual deduction (C or D, whichever is less)* | F<br>Balance at the end of the year (column C minus column E) |
|---|---|---|---|---|---|---|---|
| ☐ | 2014-12-31 | 1,024 | 410 | 614 | 205 | 205 | 409 |

**2** Description: Prospectus costs - 2016

| Subparagraph 20(1)(e)(v) is applicable in the taxation year* | Date of expense | A<br>Expense amount | B<br>Amounts deductible in the preceding taxation years | C<br>Balance before the annual expense (column A minus column B) | D<br>20 % of amount A x number of days in the taxation year 366 / **365** | E<br>Annual deduction (C or D, whichever is less)* | F<br>Balance at the end of the year (column C minus column E) |
|---|---|---|---|---|---|---|---|
| ☐ | 2016-12-31 | 1,738 | | 1,738 | 349 | 349 | 1,389 |

**3** Description: Underwriting fees - 2014

| Subparagraph 20(1)(e)(v) is applicable in the taxation year* | Date of expense | A<br>Expense amount | B<br>Amounts deductible in the preceding taxation years | C<br>Balance before the annual expense (column A minus column B) | D<br>20 % of amount A x number of days in the taxation year 366 / **365** | E<br>Annual deduction (C or D, whichever is less)* | F<br>Balance at the end of the year (column C minus column E) |
|---|---|---|---|---|---|---|---|
| ☐ | 2014-12-31 | 50,000 | 20,000 | 30,000 | 10,027 | 10,027 | 19,973 |

**4** Description: Underwriting fees - 2016

| Subparagraph 20(1)(e)(v) is applicable in the taxation year* | Date of expense | A<br>Expense amount | B<br>Amounts deductible in the preceding taxation years | C<br>Balance before the annual expense (column A minus column B) | D<br>20 % of amount A x number of days in the taxation year 366 / **365** | E<br>Annual deduction (C or D, whichever is less)* | F<br>Balance at the end of the year (column C minus column E) |
|---|---|---|---|---|---|---|---|
| ☐ | 2016-12-31 | 40,000 | | 40,000 | 8,022 | 8,022 | 31,978 |

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**Schedule 4**

# Corporation Loss Continuity and Application

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

## Part 1 – Non-capital losses

**Determination of current-year non-capital loss**

| | | | | | |
|---|---|---|---|---|---|
| Net income (loss) for income tax purposes | | | | -404,460 | A |
| **Deduct:** (increase a loss) | | | | | |
| Net capital losses deducted in the year (enter as a positive amount) | | | a | | |
| Taxable dividends deductible under section 112 or subsections 113(1) or 138(6) | | | b | | |
| Amount of Part VI.1 tax deductible under paragraph 110(1)(k) | | | c | | |
| Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2) | | | d | | |
| Subtotal (total of amounts a to d) | | | ► | | B |
| Subtotal (amount A **minus** amount B; if positive, enter "0") | | | | -404,460 | C |
| **Deduct:** (increase a loss) | | | | | |
| Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions | | | | | D |
| Subtotal (amount C **minus** amount D) | | | | -404,460 | E |
| **Add:** (decrease a loss) | | | | | |
| Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss) | | | | | F |
| Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0") | | | | -404,460 | G |
| If amount G is negative, enter it on line 110 as a positive. | | | | | |

**Continuity of non-capital losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Non-capital loss at the end of the previous tax year | | | e | | |
| **Deduct:** Non-capital loss expired (note 1) | 100 | | f | | |
| Non-capital losses at the beginning of the tax year (amount e **minus** amount f) | 102 | | | | H |
| **Add:** | | | | | |
| Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary (note 2) corporation | 105 | | g | | |
| Current-year non-capital loss (from amount G) | 110 | 404,460 | h | | |
| Subtotal (amount g **plus** amount h) | | 404,460 | | 404,460 | I |
| Subtotal (amount H **plus** amount I) | | | | 404,460 | J |

Note 1: A non-capital loss expires as follows:

- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

## Part 1 – Non-capital losses (continued)

**Deduct:**

| | | | | | |
|---|---|---|---|---|---|
| Other adjustments (includes adjustments for an acquisition of control) | 150 | | i | | |
| Section 80 – Adjustments for forgiven amounts | 140 | | j | | |
| Subsection 111(10) – Adjustments for fuel tax rebate | | | j.1 | | |
| Non-capital losses of previous tax years applied in the current tax year<br>Enter amount k on line 331 of the T2 Return. | 130 | | k | | |
| Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (note 3) | 135 | | l | | |
| Subtotal (total of amounts i to l) | | | | | K |
| Non-capital losses before any request for a carryback (amount J **minus** amount K) | | | | 404,460 | L |

**Deduct** – **Request to carry back non-capital loss to:**

| | | | | | |
|---|---|---|---|---|---|
| First previous tax year to reduce taxable income | 901 | 203,578 | m | | |
| Second previous tax year to reduce taxable income | 902 | 3,293 | n | | |
| Third previous tax year to reduce taxable income | 903 | | o | | |
| First previous tax year to reduce taxable dividends subject to Part IV tax | 911 | | p | | |
| Second previous tax year to reduce taxable dividends subject to Part IV tax | 912 | | q | | |
| Third previous tax year to reduce taxable dividends subject to Part IV tax | 913 | | r | | |
| Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r) | | 206,871 | | 206,871 | M |
| Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M) | 180 | | | 197,589 | N |

Note 3: Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

## Part 2 – Capital losses

**Continuity of capital losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Capital losses at the end of the previous tax year | 200 | | a | | |
| Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation | 205 | | b | | |
| Subtotal (amount a **plus** amount b) | | | | | A |
| **Deduct:** | | | | | |
| Other adjustments (includes adjustments for an acquisition of control) | 250 | | c | | |
| Section 80 – Adjustments for forgiven amounts | 240 | | d | | |
| Subtotal (amount c **plus** amount d) | | | | | B |
| Subtotal (amount A **minus** amount B) | | | | | C |
| **Add:** Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*) | 210 | | | | D |
| Unused non-capital losses that expired in the tax year (note 4) | | | e | | |
| Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year (note 5) | | | f | | |
| Enter amount e or f, whichever is less | 215 | | g | | |
| ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000 | 220 | | | | E |
| Subtotal (total of amounts C to E) | | | | | F |

**Note**

If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220 above.

Note 4: If the loss was incurred in a tax year ending after March 22, 2004, determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not used in previous years and the current year on line e.

Note 5: If the ABILs were incurred in a tax year ending after March 22, 2004, enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on line f.

## Part 2 – Capital losses (continued)

**Deduct:** Capital losses from previous tax years applied against the current-year net capital gain (note 6) . . . **225** ______ G

Capital losses before any request for a carryback (amount F **minus** amount G) ______ H

**Deduct** – **Request to carry back capital loss to** (note 7):

| | Capital gain (100%) | | Amount carried back (100%) | |
|---|---|---|---|---|
| First previous tax year | | 951 | | h |
| Second previous tax year | | 952 | | i |
| Third previous tax year | | 953 | | j |

Subtotal (total of amounts h to j) ______ ______ I

Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I) **280** ______ J

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current-year tax, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, divide this amount by 2. The result represents the 50% inclusion rate.

## Part 3 – Farm losses

**Continuity of farm losses and request for a carryback**

Farm losses at the end of the previous tax year . . . ______ a

**Deduct:** Farm loss expired (note 8) . . . **300** ______ b

Farm losses at the beginning of the tax year (amount a **minus** amount b) . . . **302** ______ ______ A

**Add:**

Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation . . . **305** ______ c

Current-year farm loss (amount F in Part 1) . . . **310** ______ d

Subtotal (amount c **plus** amount d) ______ ______ B

Subtotal (amount A **plus** amount B) ______ C

**Deduct:**

Other adjustments (includes adjustments for an acquisition of control) . . . **350** ______ e

Section 80 – Adjustments for forgiven amounts . . . **340** ______ f

Farm losses of previous tax years applied in the current tax year . . . **330** ______ g
Enter amount g on line 334 of the T2 Return.

Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (note 9) . . . **335** ______ h

Subtotal (total of amounts e to h) ______ ______ D

Farm losses before any request for a carryback (amount C **minus** amount D) ______ E

**Deduct** – **Request to carry back farm loss to:**

First previous tax year to reduce taxable income . . . **921** ______ i

Second previous tax year to reduce taxable income . . . **922** ______ j

Third previous tax year to reduce taxable income . . . **923** ______ k

First previous tax year to reduce taxable dividends subject to Part IV tax . . . **931** ______ l

Second previous tax year to reduce taxable dividends subject to Part IV tax . . . **932** ______ m

Third previous tax year to reduce taxable dividends subject to Part IV tax . . . **933** ______ n

Subtotal (total of amounts i to n) ______ ______ F

Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F) **380** ______ G

Note 8: A farm loss expires as follows:
after **10** tax years if it arose in a tax year ending before 2006; and
after **20** tax years if it arose in a tax year ending after 2005.

Note 9: Amount h is the total of lines 340 and 345 from Schedule 3.

## Part 4 – Restricted farm losses

**Current-year restricted farm loss**

Total losses for the year from farming business . . . **485** ______ A

**Minus** the deductible farm loss:

(amount A above ______ – $2,500) **divided** by 2 = ______ a

Amount a or $ 15,000 (note 10), whichever is less . . . ______ ______ b

2,500 c

Subtotal (amount b **plus** amount c) 2,500 | 2,500 B

Current-year restricted farm loss (amount A **minus** amount B) ______ C

**Continuity of restricted farm losses and request for a carryback**

Restricted farm losses at the end of the previous tax year . . . ______ d

**Deduct:** Restricted farm loss expired (note 11) . . . **400** ______ e

Restricted farm losses at the beginning of the tax year (amount d **minus** amount e) . . . **402** ______ ______ D

**Add:**

Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation . . . **405** ______ f

Current-year restricted farm loss (from amount C) . . . **410** ______ g

Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.

Subtotal (amount f **plus** amount g) ______ ______ E

Subtotal (amount D **plus** amount E) ______ F

**Deduct:**

Restricted farm losses from previous tax years applied against current farming income . . . **430** ______ h

Enter amount h on line 333 of the T2 return.

Section 80 – Adjustments for forgiven amounts . . . **440** ______ i

Other adjustments . . . **450** ______ j

Subtotal (total of amounts h to j) ______ ______ G

Restricted farm losses before any request for a carryback (amount F **minus** amount G) ______ H

**Deduct** – **Request to carry back restricted farm loss to:**

First previous tax year to reduce farming income . . . **941** ______ k

Second previous tax year to reduce farming income . . . **942** ______ l

Third previous tax year to reduce farming income . . . **943** ______ m

Subtotal (total of amounts k to m) ______ ______ I

Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I) **480** ______ J

**Note**

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 10: For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

Note 11: A restricted farm loss expires as follows:
after **10** tax years if it arose in a tax year ending before 2006; and
after **20** tax years if it arose in a tax year ending after 2005.

## Part 5 – Listed personal property losses

**Continuity of listed personal property loss and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Listed personal property losses at the end of the previous tax year | | | a | | |
| **Deduct:** Listed personal property loss expired after 7 tax years | 500 | | b | | |
| Listed personal property losses at the beginning of the tax year (amount a **minus** amount b) | 502 | | | | A |
| **Add:** Current-year listed personal property loss (from Schedule 6) | | | | 510 | B |
| Subtotal (amount A **plus** amount B) | | | | | C |
| **Deduct:** | | | | | |
| Listed personal property losses from previous tax years applied against listed personal property gains | 530 | | c | | |
| Enter amount c on line 655 of Schedule 6. | | | | | |
| Other adjustments | 550 | | d | | |
| Subtotal (amount c **plus** amount d) | | | | | D |
| Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D) | | | | | E |
| **Deduct – Request to carry back listed personal property loss to:** | | | | | |
| First previous tax year to reduce listed personal property gains | 961 | | e | | |
| Second previous tax year to reduce listed personal property gains | 962 | | f | | |
| Third previous tax year to reduce listed personal property gains | 963 | | g | | |
| Subtotal (total of amounts e to g) | | | | | F |
| Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F) | | | | 580 | G |

## Part 7 – Limited partnership losses

### Current-year limited partnership losses

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| | Partnership account number | Tax year ending yyyy/mm/dd | Corporation's share of limited partnership loss | Corporation's at-risk amount | Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses | Column 4 **minus** column 5 (if negative, enter "0") | Current -year limited partnership losses (column 3 **minus** column 6) |
| | 600 | 602 | 604 | 606 | 608 | | 620 |
| 1. | | | | | | | |
| | | | | | | **Total** (enter this amount on line 222 of Schedule 1) | |

### Limited partnership losses from previous tax years that may be applied in the current year

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| | Partnership account number | Tax year ending yyyy/mm/dd | Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary | Corporation's at-risk amount | Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses | Column 4 **minus** column 5 (if negative, enter "0") | Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) |
| | 630 | 632 | 634 | 636 | 638 | | 650 |
| 1. | | | | | | | |

### Continuity of limited partnership losses that can be carried forward to future tax years

| | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| | Partnership account number | Limited partnership losses at the end of the previous tax year | Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary | Current-year limited partnership losses (from line 620) | Limited partnership losses applied in the current year (must be equal to or less than line 650) | Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) |
| | 660 | 662 | 664 | 670 | 675 | 680 |
| 1. | | | | | | |
| | | | | **Total** (enter this amount on line 335 of the T2 return) | | |

**Note**

If you need more space, you can attach more schedules.

## Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

**Note**

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*.

# Non-Capital Loss Continuity Workchart

## Part 6 – Analysis of balance of losses by year of origin

## Non-capital losses – losses that can be carried forward over 20 years

| Year of origin | Balance at beginning of year | Loss incurred in current year | Adjustments and transfers | Loss carried back Parts I & IV | Applied to reduce: Taxable income | Applied to reduce: Part IV tax | Balance at end of year |
|---|---|---|---|---|---|---|---|
| Current | N/A | 404,460 | | 206,871 | N/A | | 197,589 |
| 1st preceding taxation year 2015-12-31 | | N/A | | N/A | | | |
| 2nd preceding taxation year 2015-11-04 | | N/A | | N/A | | | |
| 3rd preceding taxation year 2015-10-31 | | N/A | | N/A | | | |
| 4th preceding taxation year 2014-12-31 | | N/A | | N/A | | | |
| 5th preceding taxation year 2013-12-31 | | N/A | | N/A | | | |
| 6th preceding taxation year 2012-12-31 | | N/A | | N/A | | | |
| 7th preceding taxation year 2011-12-31 | | N/A | | N/A | | | |
| 8th preceding taxation year 2010-12-31 | | N/A | | N/A | | | |
| 9th preceding taxation year 2009-12-31 | | N/A | | N/A | | | |
| 10th preceding taxation year 2008-12-31 | | N/A | | N/A | | | |
| 11th preceding taxation year 2007-12-31 | | N/A | | N/A | | | |
| 12th preceding taxation year 2006-12-31 | | N/A | | N/A | | | |
| 13th preceding taxation year 2005-12-31 | | N/A | | N/A | | | |
| 14th preceding taxation year 2004-12-31 | | N/A | | N/A | | | |
| 15th preceding taxation year 2003-12-31 | | N/A | | N/A | | | |
| 16th preceding taxation year 2002-12-31 | | N/A | | N/A | | | |
| 17th preceding taxation year 2001-12-31 | | N/A | | N/A | | | |
| 18th preceding taxation year 2000-12-31 | | N/A | | N/A | | | |
| 19th preceding taxation year 1999-12-31 | | N/A | | N/A | | | |
| 20th preceding taxation year | | N/A | | N/A | | | * |
| **Total** | | 404,460 | | 206,871 | | | 197,589 |

* **This balance expires this year and will not be available next year.**

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**Schedule 5**

# Tax Calculation Supplementary – Corporations

| Corporation's name | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

## Part 1 – Allocation of taxable income

**100** Enter the Regulation that applies (402 to 413).

| A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year.* | | B Total salaries and wages paid in jurisdiction | C (B x taxable income) / G | D Gross revenue | E (D x taxable income) / H | F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2) |
|---|---|---|---|---|---|---|
| Newfoundland and Labrador | 003 1 Yes | 103 | | 143 | | |
| Newfoundland and Labrador Offshore | 004 1 Yes | 104 | | 144 | | |
| Prince Edward Island | 005 1 Yes | 105 | | 145 | | |
| Nova Scotia | 007 1 Yes | 107 | | 147 | | |
| Nova Scotia Offshore | 008 1 Yes | 108 | | 148 | | |
| New Brunswick | 009 1 Yes | 109 | | 149 | | |
| Quebec | 011 1 Yes | 111 | | 151 | | |
| Ontario | 013 1 Yes | 113 | | 153 | | |
| Manitoba | 015 1 Yes | 115 | | 155 | | |
| Saskatchewan | 017 1 Yes | 117 | | 157 | | |
| Alberta | 019 1 Yes | 119 | | 159 | | |
| British Columbia | 021 1 Yes | 121 | | 161 | | |
| Yukon | 023 1 Yes | 123 | | 163 | | |
| Northwest Territories | 025 1 Yes | 125 | | 165 | | |
| Nunavut | 026 1 Yes | 126 | | 166 | | |
| Outside Canada | 027 1 Yes | 127 | | 167 | | |
| **Total** | | 129 G | | 169 H | | |

* "Permanent establishment" is defined in subsection 400(2).

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

**Notes:**

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. If the corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

## Part 2 – Ontario tax payable, tax credits, and rebates

| Total taxable income | Income eligible for small business deduction | Provincial or territorial allocation of taxable income | Provincial or territorial tax payable before credits |
|---|---|---|---|
| | | | |

| | Code | Amount | Total | Line |
|---|---|---|---|---|
| **Ontario basic income tax** (from Schedule 500) | 270 | | | |
| **Deduct:** Ontario small business deduction (from Schedule 500) | 402 | | | |
| Subtotal | | | | A6 |
| **Add:** | | | | |
| Ontario additional tax re Crown royalties (from Schedule 504) | 274 | | | |
| Ontario transitional tax debits (from Schedule 506) | 276 | | | |
| Recapture of Ontario research and development tax credit (from Schedule 508) | 277 | | | |
| Subtotal | | | | B6 |
| Subtotal (amount A6 **plus** amount B6) | | | | C6 |
| **Deduct:** | | | | |
| Ontario resource tax credit (from Schedule 504) | 404 | | | |
| Ontario tax credit for manufacturing and processing (from Schedule 502) | 406 | | | |
| Ontario foreign tax credit (from Schedule 21) | 408 | | | |
| Ontario credit union tax reduction (from Schedule 500) | 410 | | | |
| Ontario political contributions tax credit (from Schedule 525) | 415 | | | |
| Subtotal | | | | D6 |
| Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") | | | | E6 |
| **Deduct:** Ontario research and development tax credit (from Schedule 508) | 416 | | | |
| Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0") | | | | F6 |
| **Deduct:** | | | | |
| Ontario corporate minimum tax credit (from Schedule 510) | 418 | | | |
| Ontario community food program donation tax credit for farmers (from Schedule 2) | 420 | | | |
| Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0") | | | | G6 |
| **Add:** | | | | |
| Ontario corporate minimum tax (from Schedule 510) | 278 | 12,439 | | |
| Ontario special additional tax on life insurance corporations (from Schedule 512) | 280 | | | |
| Subtotal | | 12,439 | 12,439 | H6 |
| Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) | | | 12,439 | I6 |
| **Deduct:** | | | | |
| Ontario qualifying environmental trust tax credit | 450 | | | |
| Ontario co-operative education tax credit (from Schedule 550) | 452 | 12,000 | | |
| Ontario apprenticeship training tax credit (from Schedule 552) | 454 | 29,672 | | |
| Ontario computer animation and special effects tax credit (from Schedule 554) | 456 | | | |
| Ontario film and television tax credit (from Schedule 556) | 458 | | | |
| Ontario production services tax credit (from Schedule 558) | 460 | | | |
| Ontario interactive digital media tax credit (from Schedule 560) | 462 | | | |
| Ontario sound recording tax credit (from Schedule 562) | 464 | | | |
| Ontario book publishing tax credit (from Schedule 564) | 466 | | | |
| Ontario innovation tax credit (from Schedule 566) | 468 | | | |
| Ontario business-research institute tax credit (from Schedule 568) | 470 | | | |
| Subtotal | | 41,672 | 41,672 | J6 |
| **Net Ontario tax payable or refundable credit** (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255. | 290 | | -29,233 | K6 |

## Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

| | | |
|---|---|---|
| **Net provincial and territorial tax payable or refundable credits** | 255 | -29,233 |

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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**Schedule 8**

# Capital Cost Allowance (CCA)

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes [ ] 2 No [X]

| | 1 Class number (See Note) 200 | Description | 2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201 | 3 Cost of acquisitions during the year (new property must be available for use)* 203 | 4 Adjustments and transfers** 205 | 5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207 | 6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211 | 7 Reduced undepreciated capital cost | 8 CCA rate % **** 212 | 9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213 | 10 Terminal loss (line 404 of Schedule 1) 215 | 11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217 | 12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | 15,353,748 | 860,207 | | 0 | 430,104 | 15,783,851 | 4 | 0 | 0 | 631,354 | 15,582,601 |
| 2. | 2 | | 90,895 | | | 0 | | 90,895 | 6 | 0 | 0 | 5,454 | 85,441 |
| 3. | 3 | | 743 | | | 0 | | 743 | 5 | 0 | 0 | 37 | 706 |
| 4. | 6 | | 5,821,426 | | | 0 | | 5,821,426 | 10 | 0 | 0 | 582,143 | 5,239,283 |
| 5. | 8 | | 1,069,640 | 95,257 | | 0 | 47,629 | 1,117,268 | 20 | 0 | 0 | 223,454 | 941,443 |
| 6. | 10 | | 802,519 | | | 0 | | 802,519 | 30 | 0 | 0 | 240,756 | 561,763 |
| 7. | 17 | | 16,414,846 | 1,941,193 | | 0 | 970,597 | 17,385,442 | 8 | 0 | 0 | 1,390,835 | 16,965,204 |
| 8. | 43.1 | | 1,210,342 | | | 0 | | 1,210,342 | 30 | 0 | 0 | 363,103 | 847,239 |
| 9. | 45 | | 2,237 | | | 0 | | 2,237 | 45 | 0 | 0 | 1,007 | 1,230 |
| 10. | 47 | | 8,435,008 | 564,965 | | 0 | 282,483 | 8,717,490 | 8 | 0 | 0 | 697,399 | 8,302,574 |
| 11. | 13 | Bisco Water Well | 46,255 | | | 0 | | 46,255 | NA | 0 | 0 | 4,233 | 42,022 |
| 12. | 13 | Hillsport Water Well | 39,679 | | | 0 | | 39,679 | NA | 0 | 0 | 1,107 | 38,572 |
| 13. | 13 | Oba Water Well | 17,924 | | | 0 | | 17,924 | NA | 0 | 0 | 3,000 | 14,924 |
| 14. | 94 | Construction in progress | 1,120,128 | | -1,120,128 | 0 | | | 0 | 0 | 0 | | |
| 15. | 94 | Future use | 1,902,342 | | -1,902,342 | 0 | | | 0 | 0 | 0 | | |
| 16. | 94 | Land | 359,667 | | -359,667 | 0 | | | 0 | 0 | 0 | | |
| 17. | 94 | Landscaping | 47,952 | | -47,952 | 0 | | | 0 | 0 | 0 | | |
| 18. | 12 | | 715 | 223 | | 0 | 112 | 826 | 100 | 0 | 0 | 826 | 112 |
| | | **Totals** | 52,736,066 | 3,461,845 | -3,430,089 | | 1,730,925 | 51,036,897 | | | | 4,144,708 | 48,623,114 |

**Note:** Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost. Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (14) Canada

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**SCHEDULE 9**

# RELATED AND ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

| | Name<br>100 | Country of residence (other than Canada)<br>200 | Business number (see note 1)<br>300 | Relationship code (see note 2)<br>400 | Number of common shares you own<br>500 | % of common shares you own<br>550 | Number of preferred shares you own<br>600 | % of preferred shares you own<br>650 | Book value of capital stock<br>700 |
|---|---|---|---|---|---|---|---|---|---|
| 1. | HYDRO ONE LIMITED | CA | 80512 9962 RC0001 | 3 | | | | | |
| 2. | HYDRO ONE INC. | CA | 86999 4731 RC0001 | 1 | | | | | |
| 3. | 2486267 ONTARIO INC | CA | 80232 6124 RC0001 | 3 | | | | | |
| 4. | 2486268 ONTARIO INC | CA | 80167 4078 RC0001 | 3 | | | | | |
| 5. | HYDRO ONE NETWORKS INC. | CA | 87086 5821 RC0001 | 3 | | | | | |
| 6. | HYDRO ONE TELECOM INC. | CA | 86800 1066 RC0001 | 3 | | | | | |
| 7. | HYDRO ONE TELECOM LINK LIMITE | CA | 88786 7513 RC0001 | 3 | | | | | |
| 8. | MUNICIPAL BILLING SERVICES INC | CA | 87560 6519 RC0001 | 3 | | | | | |
| 9. | HYDRO ONE LAKE ERIE LINK MANA | CA | 87892 1519 RC0002 | 3 | | | | | |
| 10. | 1938454 ONTARIO INC. | CA | 86391 7795 RC0002 | 3 | | | | | |
| 11. | 1943404 ONTARIO INC. | CA | 86248 6123 RC0002 | 3 | | | | | |
| 12. | B2M GP INC. | CA | 81838 1840 RC0001 | 3 | | | | | |
| 13. | HYDRO ONE B2M HOLDINGS INC | CA | 82217 7531 RC0001 | 3 | | | | | |
| 14. | HYDRO ONE B2M LP INC. | CA | 81838 2046 RC0001 | 3 | | | | | |
| 15. | NORFOLK ENERGY INC | CA | 86289 0399 RC0001 | 3 | | | | | |
| 16. | NORFOLK POWER DISTRIBUTION I | CA | 86289 2593 RC0001 | 3 | | | | | |
| 17. | HALDIMAND COUNTY ENERGY INC | CA | 89076 2412 RC0001 | 3 | | | | | |
| 18. | HALDIMAND COUNTY HYDRO INC | CA | 89075 9814 RC0001 | 3 | | | | | |
| 19. | WOODSTOCK HYDRO SERVICES IN | CA | 89909 5012 RC0001 | 3 | | | | | |
| 20. | 1937672 ONTARIO INC. | CA | 81722 4561 RC0001 | 3 | | | | | |
| 21. | GREAT LAKES POWER TRANSMISSI | CA | 83008 2335 RC0001 | 3 | | | | | |
| 22. | GREAT LAKES POWER TRANSMISSI | CA | 84500 6386 RC0001 | 3 | | | | | |
| 23. | GREAT LAKES POWER TRANSMISSI | CA | 82511 0216 RC0001 | 3 | | | | | |
| 24. | 1228185 ONTARIO INC. | CA | 88706 6090 RC0001 | 3 | | | | | |
| 25. | EAST WEST TIE INC. | CA | 80044 2113 RC0001 | 3 | | | | | |
| 26. | HYDRO ONE EAST-WEST TIE INC. | CA | 80105 5880 RC0001 | 3 | | | | | |
| 27. | 1937680 ONTARIO INC. | CA | 81930 4924 RC0001 | 3 | | | | | |
| 28. | 1937681 ONTARIO INC. | CA | 81722 4363 RC0001 | 3 | | | | | |
| 29. | Additional details available upon rec | CA | NR | 3 | | | | | |

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11) Canada

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**SCHEDULE 10**

# CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

## Part 1 – Calculation of current year deduction and carry-forward

**Cumulative eligible capital - Balance at the end of the preceding taxation year** (if negative, enter "0") . . . 200 — 17,891,747 A

**Add:**
- Cost of eligible capital property acquired during the taxation year . . . 222 ______
- Other adjustments . . . 226 ______
- Subtotal (line 222 plus line 226) ______ x 3 / 4 = ______ B
- Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . . 228 ______ x 1 / 2 = ______ C
- amount B minus amount C (if negative, enter "0") ______ ______ D
- Amount transferred on amalgamation or wind-up of subsidiary . . . 224 ______ E
- Subtotal (add amounts A, D, and E) 230 — 17,891,747 F

**Deduct:**
- Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . 242 ______ G
- The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . 244 ______ H
- Other adjustments . . . 246 ______ I
- (add amounts G,H, and I) ______ x 3 / 4 = 248 ______ J

**Cumulative eligible capital balance** (amount F minus amount J) . . . 17,891,747 K
(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business 249 ______

amount K 17,891,747
**less** amount from line 249 ______

**Current year deduction** . . . 17,891,747 x 7.00 % = 250 — 1,252,422 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 1,252,422 — 1,252,422 L

**Cumulative eligible capital – Closing balance** (amount K minus amount L) (if negative, enter "0") . . . 300 — 16,639,325 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

## Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

| | | | | | | |
|---|---|---|---|---|---|---|
| Amount from line K (show as positive amount) | | | | | | N |
| Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988 | | | 400 | | 1 | |
| Total of all amounts which reduced CEC in the current or prior years under subsection 80(7) | | | 401 | | 2 | |
| Total of CEC deductions claimed for taxation years beginning before July 1, 1988 | 402 | | 3 | | | |
| Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988 | 408 | | 4 | | | |
| Line 3 minus line 4 (if negative, enter "0") | | | | | 5 | |
| Total of lines 1, 2 and 5 | | | | | 6 | |
| Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400 | | | 7 | | | |
| Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000 | | | 8 | | | |
| Subtotal (line 7 plus line 8) | 409 | | | | 9 | |
| Line 6 minus line 9 (if negative, enter "0") | | | | | | O |
| Line N minus line O (if negative, enter "0") | | | | | | P |
| Line 5 | | x 1 / 2 = | | | | Q |
| Line P minus line Q (if negative, enter "0") | | | | | | R |
| Amount R | | x 2 / 3 = | | | | S |
| Amount N or amount O, whichever is less | | | | | | T |
| **Amount to be included in income** (amount S plus amount T) (enter this amount on line 108 of Schedule 1) | | | | 410 | | |

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**SCHEDULE 13**

# CONTINUITY OF RESERVES

| Name of corporation | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

## Part 1 – Capital gains reserves

| | Description of property 001 | Balance at the beginning of the year $ 002 | Transfer on an amalgamation or the wind-up of a subsidiary $ 003 | Add $ | Deduct $ | Balance at the end of the year $ 004 |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| | Totals | 008 | 009 | | | 010 |

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

## Part 2 – Other reserves

| Description | | Balance at the beginning of the year $ | Transfer on an amalgamation or the wind-up of a subsidiary $ | Add $ | Deduct $ | Balance at the end of the year $ |
|---|---|---|---|---|---|---|
| Reserve for doubtful debts ...... | | 110 | 115 | | | 120 |
| Reserve for undelivered goods and services not rendered ...... | X | 130 | 135 | 114,586 | | 140 114,586 |
| Reserve for prepaid rent ....... | | 150 | 155 | | | 160 |
| Reserve for refundable containers .. | | 190 | 195 | | | 200 |
| Reserve for unpaid amounts ..... | | 210 | 215 | | | 220 |
| Other tax reserves ........... | | 230 | 235 | | | 240 |
| Totals | | 270 | 275 | 114,586 | | 280 114,586 |

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

# Continuity of financial statement reserves (not deductible)

## Financial statement reserves (not deductible)

| | Description | Balance at the beginning of the year | Transfer on an amalgamation or the wind-up of a subsidiary | Add | Deduct | Balance at the end of the year |
|---|---|---|---|---|---|---|
| 1 | OPEB Liability | 13,890,230 | | 1,198,398 | | 15,088,628 |
| 2 | Reg Asset re RRPR Var (42719: | -2,759,933 | | 1,115,610 | | -1,644,323 |
| 3 | Enviromental Liabilities | 11,051,081 | | 24,794,042 | | 35,845,123 |
| 4 | Reg asset re Environ. Liabilities | | | -35,845,123 | | -35,845,123 |
| 5 | Bonus accrual - 413741 | | | 37,131 | | 37,131 |
| 6 | | | | | | |
| | Reserves from Part 2 of Schedule 13 | | | 114,586 | | 114,586 |
| | **Totals** | 22,181,378 | | -8,585,356 | | 13,596,022 |

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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**SCHEDULE 14**

# MISCELLANEOUS PAYMENTS TO RESIDENTS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

| | Name of recipient 100 | Address of recipient 200 | Royalties 300 | Research and development fees 400 | Management fees 500 | Technical assistance fees 600 | Similar payments 700 |
|---|---|---|---|---|---|---|---|
| 1 | Hydro One Networks Inc. | 8th Floor South Tower<br>483 Bay Street<br>Toronto<br>ON CA<br>M5G 2P5 | | | 1,050,603 | | |
| 2 | Hydro One Inc | 8th Floor South Tower<br>483 Bay Street<br>Toronto<br>ON CA<br>M5G 2P5 | | | 92,827 | | |

T2 SCH 14 (99)

Canada

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**Schedule 15**

# Deferred Income Plans

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

| | Type of plan (see note 1) 100 | Amount of contribution $ (see note 2) 200 | Registration number (RPP, RSUBP, PRPP, and DPSP only) 300 | Name of EPSP trust 400 | Address of EPSP trust 500 | T4PS slip(s) (see note 3) 600 |
|---|---|---|---|---|---|---|
| 1 | 1 | 996,978 | 1059104 | | | |
| 2 | 1 | 7,581 | 1289982 | | | |

**Note 1**

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

**Note 2**

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . . . . . . . . . . . . . . . . 1,004,559 A

**Less:**

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 717,246 B

**Deductible amount for contributions to deferred income plans**
(amount A **minus** amount B) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . 287,313 C

Enter amount C on line 417 of Schedule 1

**Note 3**

T4PS slip(s) filed by: 1 – Trustee
2 – Employer
(EPSP only)

T2 SCH 15 (13)

Canada

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 29**

# PAYMENTS TO NON-RESIDENTS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- A corporation that makes payments or credits amounts to non-residents under subsections 202(1) and 105(1) of the *Income Tax Regulations* has to file the applicable information return.
- The corporation has to complete the information below for all amounts paid or credited to non-residents that are listed in Note 1. If the total amount paid or credited is less than $100, you do not have to complete the information for that payee.

| | Name (list each payee separately) 100 | Address 200 | Payment code (see note 1) 300 | Amount $ 400 |
|---|---|---|---|---|
| 1 | SEL Schweitzer Laboratories Inc. | NE 2350 Hopkins Crt<br><br>Pullman<br>WA US 99163 | 09 | 14,812 |

Note 1: Enter the applicable payment code in column 300:

1 – Royalties
2 – Rents
3 – Management fees/commissions
4 – Technical assistance fees
5 – Research and development fees
6 – Interest
7 – Dividends
8 – Film payments: – motion picture film, or – a film or video tape for use in connection with television
9 – Other services

T2 SCH 29 (99)

Canada

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 33**

# Taxable Capital Employed in Canada – Large Corporations

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

## Part 1 – Capital

**Add** the following year-end amounts:

| | Line | Amount | | |
|---|---|---|---|---|
| Reserves that have not been deducted in calculating income for the year under Part I | 101 | 49,289,428 | | |
| Capital stock (or members' contributions if incorporated without share capital) | 103 | 5,000,000 | | |
| Retained earnings | 104 | | | |
| Contributed surplus | 105 | | | |
| Any other surpluses | 106 | | | |
| Deferred unrealized foreign exchange gains | 107 | | | |
| All loans and advances to the corporation | 108 | | | |
| All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations | 109 | 42,783,000 | | |
| Any dividends declared but not paid by the corporation before the end of the year | 110 | | | |
| All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year | 111 | | | |
| The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below) | 112 | | | |
| Subtotal (**add** lines 101 to 112) | | 97,072,428 | 97,072,428 | A |

**Note:**

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if

a) those lines applied to partnerships in the same manner that they apply to corporations, and

b) those amounts were computed without reference to amounts owing by the partnership

(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or

(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

## Part 1 – Capital (continued)

| | | | | |
|---|---|---|---|---|
| Subtotal A (from page 1) | | | 97,072,428 | A |
| **Deduct** the following amounts: | | | | |
| Deferred tax debit balance at the end of the year | 121 | 4,218,000 | | |
| Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year | 122 | 4,393,291 | | |
| To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year. | 123 | | | |
| Deferred unrealized foreign exchange losses at the end of the year | 124 | | | |
| Subtotal (**add** lines 121 to 124) | | 8,611,291 | 8,611,291 | B |
| **Capital for the year** (amount A **minus** amount B) (if negative, enter "0") | 190 | | 88,461,137 | |

## Part 2 – Investment allowance

**Add** the carrying value at the end of the year of the following assets of the corporation:

| | | |
|---|---|---|
| A share of another corporation | 401 | |
| A loan or advance to another corporation (other than a financial institution) | 402 | 7,253,000 |
| A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution) | 403 | |
| Long-term debt of a financial institution | 404 | |
| A dividend payable on a share of the capital stock of another corporation | 405 | |
| A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1) | 406 | |
| An interest in a partnership (see note 2 below) | 407 | |
| **Investment allowance for the year** (add lines 401 to 407) | 490 | 7,253,000 |

**Notes:**

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

## Part 3 – Taxable capital

| | | | |
|---|---|---|---|
| Capital for the year (line 190) | | 88,461,137 | C |
| **Deduct:** Investment allowance for the year (line 490) | | 7,253,000 | D |
| **Taxable capital for the year** (amount C **minus** amount D) (if negative, enter "0") | 500 | 81,208,137 | |

## Part 4 – Taxable capital employed in Canada

**To be completed by a corporation that was resident in Canada at any time in the year**

Taxable capital for the year (line 500) 81,208,137 x Taxable income earned in Canada **610** 1,000 / Taxable income 1,000 = **Taxable capital employed in Canada** **690** 81,208,137

**Notes:** 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

**To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada**

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ____________

**Deduct** the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . . . . . . . . . . . . . . . . . **711** ____________

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **712** ____________

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . . . . . . . . **713** ____________

Total deductions (**add** lines 711, 712, and 713) ____________ ____________ E

**Taxable capital employed in Canada** (line 701 **minus** amount E) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . **790** ____________

**Note:** Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

## Part 5 – Calculation for purposes of the small business deduction

**This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.**

Taxable capital employed in Canada (amount from line 690) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ____________ F

**Deduct:** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") ____________ H

**Calculation for purposes of the small business deduction** (amount H x 0.225%) . . . . . . . . . . . . . . . . . . . . . . . . . . . ____________ I

Enter this amount at line 415 of the T2 return.

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**Schedule 88**

# Internet Business Activities

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- File this schedule if your corporation earns income from one or more webpages or websites.
- You may earn income from your webpages or websites if:
  - you sell goods and/or services on your own pages or websites. You may have a shopping cart and process payment transactions yourself or through a third-party service;
  - your site doesn't support transactions but your customers call, complete, and submit a form, or email you to make a purchase, order, booking, and others;
  - you sell goods and/or services on auction, marketplace, or similar websites operated by others; or
  - you earn income from advertising, income programs, or traffic your site generates. For example:
    - static advertisements you place on your site for other businesses
    - affiliate programs
    - advertising programs such as Google AdSense or Microsoft adCentre
    - other types of traffic programs.
- Also file this schedule if you don't have a website but you have created a profile or other page describing your business on blogs, auction, market place, or any other portal or directory websites from which you earn income.
- File this schedule with your *T2 – Corporation Income Tax Return*.

How many Internet webpages or websites does your corporation earn income from? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1

Provide the Internet webpage or website addresses (also known as URL addresses)*:

http:// http://www.hydroone.com/OURCOMMITMENT/REMOTECOMMUNITIES/Pages/home.aspx

http://

http://

http://

http://

What is the percentage of the corporation's gross revenue generated from the Internet in comparison to the corporation's total gross revenue? . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 0.001 %

* If you have more than five websites, enter the addresses of those that generate the most Internet income. If you don't have a website but you have created a profile or other page describing your business on blogs, auction, market place, or any other portal or directory websites, enter the addresses of the pages if they generate income.

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**Schedule 510**

# Ontario Corporate Minimum Tax

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Determination of CMT applicability

| | | |
|---|---|---|
| Total assets of the corporation at the end of the tax year * | 112 | 104,403,000 |
| Share of total assets from partnership(s) and joint venture(s) * | 114 | |
| Total assets of associated corporations (amount from line 450 on Schedule 511) | 116 | 50,000,000 |
| Total assets (total of lines 112 to 116) | | 154,403,000 |
| Total revenue of the corporation for the tax year ** | 142 | 50,357,000 |
| Share of total revenue from partnership(s) and joint venture(s) ** | 144 | |
| Total revenue of associated corporations (amount from line 550 on Schedule 511) | 146 | 100,000,000 |
| Total revenue (total of lines 142 to 146) | | 150,357,000 |

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

## Part 2 – Adjusted net income/loss for CMT purposes

| | | | | | |
|---|---|---|---|---|---|
| Net income/loss per financial statements * | | | 210 | 533,709 | |
| **Add** (to the extent reflected in income/loss): | | | | | |
| Provision for current income taxes/cost of current income taxes | 220 | | | | |
| Provision for deferred income taxes (debits)/cost of future income taxes | 222 | | | | |
| Equity losses from corporations | 224 | | | | |
| Financial statement loss from partnerships and joint ventures | 226 | | | | |
| Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act | 230 | | | | |
| **Other additions** (see note below): | | | | | |
| Share of adjusted net income of partnerships and joint ventures ** | 228 | | | | |
| Total patronage dividends received, not already included in net income/loss | 232 | | | | |
| 281 | 282 | | | | |
| 283 | 284 | | | | |
| Subtotal | | | | | A |
| **Deduct** (to the extent reflected in income/loss): | | | | | |
| Provision for recovery of current income taxes/benefit of current income taxes | 320 | 73,000 | | | |
| Provision for deferred income taxes (credits)/benefit of future income taxes | 322 | | | | |
| Equity income from corporations | 324 | | | | |
| Financial statement income from partnerships and joint ventures | 326 | | | | |
| Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act | 330 | | | | |
| Dividends not taxable under section 83 of the federal Act (from Schedule 3) | 332 | | | | |
| Gain on donation of listed security or ecological gift | 340 | | | | |
| Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act *** | 342 | | | | |
| Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act **** | 344 | | | | |
| Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act ***** | 346 | | | | |
| Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act | 348 | | | | |
| **Other deductions** (see note below): | | | | | |
| Share of adjusted net loss of partnerships and joint ventures ** | 328 | | | | |
| Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3 | 334 | | | | |
| Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss | 336 | | | | |
| Patronage dividends paid (from Schedule 16) not already included in net income/loss | 338 | | | | |
| 381 | 382 | | | | |
| 383 | 384 | | | | |
| 385 | 386 | | | | |
| 387 | 388 | | | | |
| 389 | 390 | | | | |
| Subtotal | | 73,000 | | 73,000 | B |
| Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B) | | | 490 | 460,709 | |

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

**Note**

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

## Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

## Part 3 – CMT payable

| | | | | |
|---|---|---|---|---|
| Adjusted net income for CMT purposes (line 490 in Part 2, if positive) | | 515 | 460,709 | |
| **Deduct:** | | | | |
| CMT loss available (amount R from Part 7) | | | | |
| **Minus:** Adjustment for an acquisition of control * | 518 | | | |
| Adjusted CMT loss available | | | | C |
| Net income subject to CMT calculation (if negative, enter "0") | | 520 | 460,709 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Amount from line 520 | 460,709 | x | Number of days in the tax year before July 1, 2010 / Number of days in the tax year | / 366 | x 4 % = | | 1 |
| Amount from line 520 | 460,709 | x | Number of days in the tax year after June 30, 2010 / Number of days in the tax year | 366 / 366 | x 2.7 % = | 12,439 | 2 |

Subtotal (amount 1 **plus** amount 2) ............. 12,439 3

| | | | |
|---|---|---|---|
| Gross CMT: amount on line 3 above x OAF ** | 540 | 12,439 | |
| **Deduct:** | | | |
| Foreign tax credit for CMT purposes *** | 550 | | |
| CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") | | 12,439 | D |
| **Deduct:** | | | |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | | |
| Net CMT payable (if negative, enter "0") | | 12,439 | E |

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = ______

**Ontario allocation factor** ............ 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

## Part 4 – Calculation of CMT credit carryforward

| | | | | | |
|---|---|---|---|---|---|
| CMT credit carryforward at the end of the previous tax year * | | 12,690 | G | | |
| **Deduct:** | | | | | |
| CMT credit expired * | 600 | | | | |
| CMT credit carryforward at the beginning of the current tax year * (see note below) | | 12,690 | 620 | 12,690 | |
| **Add:** | | | | | |
| CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) | | | 650 | | |
| CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) | | | | 12,690 | H |
| **Deduct:** | | | | | |
| CMT credit deducted in the current tax year (amount P from Part 5) | | | | | I |
| Subtotal (amount H **minus** amount I) | | | | 12,690 | J |
| **Add:** | | | | | |
| Net CMT payable (amount E from Part 3) | | 12,439 | | | |
| SAT payable (amount O from Part 6 of Schedule 512) | | | | | |
| Subtotal | | 12,439 | | 12,439 | K |
| CMT credit carryforward at the end of the tax year (amount J **plus** amount K) | | | 670 | 25,129 | L |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

**Note:** If you entered an amount on line 620 or line 650, complete Part 6.

## Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

| | | | | | |
|---|---|---|---|---|---|
| CMT credit available for the tax year (amount H from Part 4) | | | | 12,690 | M |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | | | | 1 |
| For a corporation that is not a life insurance corporation: | | | | | |
| CMT after foreign tax credit deduction (amount D from Part 3) | 12,439 | 2 | | | |
| For a life insurance corporation: | | | | | |
| Gross CMT (line 540 from Part 3) | | 3 | | | |
| Gross SAT (line 460 from Part 6 of Schedule 512) | | 4 | | | |
| The **greater** of amounts 3 and 4 | | 5 | | | |
| **Deduct:** line 2 or line 5, whichever applies: | | | 12,439 | 6 | |
| Subtotal (if negative, enter "0") | | | | | N |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | | | | |
| **Deduct:** | | | | | |
| Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) | | | 41,672 | | |
| Subtotal (if negative, enter "0") | | | | | O |
| CMT credit deducted in the current tax year (least of amounts M, N, and O) | | | | | P |

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

## Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | CMT credit balance * |
|---|---|
| 10th previous tax year | 680 |
| 9th previous tax year | 681 |
| 8th previous tax year | 682 |
| 7th previous tax year | 683 |
| 6th previous tax year | 684 |
| 5th previous tax year | 685 |
| 4th previous tax year | 686 |
| 3rd previous tax year | 687 |
| 2nd previous tax year | 688 |
| 1st previous tax year | 689 |
| Total ** | |

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

## Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . . . . . . . . . . . . . . . . . . . ______ Q

**Deduct:**

CMT loss expired * . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 700 ______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . . . . . . . . . . . ______ 720 ______

**Add:**

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . . . . . . . . . . . . . . 750 ______

CMT loss available (line 720 **plus** line 750) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ R

**Deduct:**

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . . . . . . ______

Subtotal (if negative, enter "0") ______ S

**Add:**

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . . . . . . . 760 ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . . . . . . . . . . . . . . . . . . . . . 770 ______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

**Note:** If you entered an amount on line 720 or line 750, complete Part 8.

## Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | Balance earned in a tax year ending before March 23, 2007 * | Balance earned in a tax year ending after March 22, 2007 ** |
|---|---|---|
| 10th previous tax year | 810 | 820 |
| 9th previous tax year | 811 | 821 |
| 8th previous tax year | 812 | 822 |
| 7th previous tax year | 813 | 823 |
| 6th previous tax year | 814 | 824 |
| 5th previous tax year | 815 | 825 |
| 4th previous tax year | 816 | 826 |
| 3rd previous tax year | 817 | 827 |
| 2nd previous tax year | 818 | 828 |
| 1st previous tax year | | 829 |
| Total *** | | |

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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**SCHEDULE 511**

# ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 1 | HYDRO ONE LIMITED | 80512 9962 RC0001 | 0 | 0 |
| 2 | HYDRO ONE INC. | 86999 4731 RC0001 | 0 | 0 |
| 3 | 2486267 ONTARIO INC | 80232 6124 RC0001 | 0 | 0 |
| 4 | 2486268 ONTARIO INC | 80167 4078 RC0001 | 0 | 0 |
| 5 | HYDRO ONE NETWORKS INC. | 87086 5821 RC0001 | 50,000,000 | 100,000,000 |
| 6 | HYDRO ONE TELECOM INC. | 86800 1066 RC0001 | 0 | 0 |
| 7 | HYDRO ONE TELECOM LINK LIMITED | 88786 7513 RC0001 | 0 | 0 |
| 8 | MUNICIPAL BILLING SERVICES INC. | 87560 6519 RC0001 | 0 | 0 |
| 9 | HYDRO ONE LAKE ERIE LINK MANAGEMENT INC | 87892 1519 RC0002 | 0 | 0 |
| 10 | 1938454 ONTARIO INC. | 86391 7795 RC0002 | 0 | 0 |
| 11 | 1943404 ONTARIO INC. | 86248 6123 RC0002 | 0 | 0 |
| 12 | B2M GP INC. | 81838 1840 RC0001 | 0 | 0 |
| 13 | HYDRO ONE B2M HOLDINGS INC | 82217 7531 RC0001 | 0 | 0 |
| 14 | HYDRO ONE B2M LP INC. | 81838 2046 RC0001 | 0 | 0 |
| 15 | NORFOLK ENERGY INC | 86289 0399 RC0001 | 0 | 0 |
| 16 | NORFOLK POWER DISTRIBUTION INC | 86289 2593 RC0001 | 0 | 0 |
| 17 | HALDIMAND COUNTY ENERGY INC | 89076 2412 RC0001 | 0 | 0 |
| 18 | HALDIMAND COUNTY HYDRO INC | 89075 9814 RC0001 | 0 | 0 |
| 19 | WOODSTOCK HYDRO SERVICES INC. | 89909 5012 RC0001 | 0 | 0 |
| 20 | 1937672 ONTARIO INC. | 81722 4561 RC0001 | 0 | 0 |
| 21 | GREAT LAKES POWER TRANSMISSION HOLDINGS IN | 83008 2335 RC0001 | 0 | 0 |
| 22 | GREAT LAKES POWER TRANSMISSION INC. | 84500 6386 RC0001 | 0 | 0 |
| 23 | GREAT LAKES POWER TRANSMISSION HOLDING COI | 82511 0216 RC0001 | 0 | 0 |
| 24 | 1228185 ONTARIO INC. | 88706 6090 RC0001 | 0 | 0 |
| 25 | EAST WEST TIE INC. | 80044 2113 RC0001 | 0 | 0 |
| 26 | HYDRO ONE EAST-WEST TIE INC. | 80105 5880 RC0001 | 0 | 0 |
| 27 | 1937680 ONTARIO INC. | 81930 4924 RC0001 | 0 | 0 |
| 28 | 1937681 ONTARIO INC. | 81722 4363 RC0001 | 0 | 0 |

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 29 | Additional details available upon request | NR | 0 | 0 |
| | | **Total** | 450 50,000,000 | 550 100,000,000 |

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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**SCHEDULE 550**

# ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

| **110** Name of person to contact for more information | **120** Telephone number including area code |
|---|---|
| GLENDY CHEUNG | (416) 345-6812 |

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

## Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 1,880,249

For eligible expenditures incurred before March 27, 2009:

– If line 300 is $400,000 or less, enter 15% on line 310.
– If line 300 is $600,000 or more, enter 10% on line 310.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \; 400{,}000}{\$ \; 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

– If line 300 is $400,000 or less, enter 30% on line 312.
– If line 300 is $600,000 or more, enter 25% on line 312.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \; 400{,}000}{\$ \; 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

| | A<br>Name of university, college, or other eligible educational institution<br>**400** | B<br>Name of qualifying co-operative education program<br>**405** |
|---|---|---|
| 1. | University of Toronto | Mechanical Engineering |
| 2. | University of Toronto | Mechanical Engineering |
| 3. | Ryerson University | Mechanical Engineering |
| 4. | Ryerson University | Mechanical Engineering |

| | C<br>Name of student<br>**410** | D<br>Start date of WP (see note 1 below)<br>**430** | E<br>End date of WP (see note 2 below)<br>**435** |
|---|---|---|---|
| 1. | [redacted] | 2016-01-01 | 2016-04-30 |
| 2. | [redacted] | 2016-05-01 | 2016-08-26 |
| 3. | [redacted] | 2016-05-02 | 2016-08-31 |
| 4. | [redacted] | 2016-09-01 | 2016-12-31 |

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

## Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

| | F1<br>Eligible expenditures before March 27, 2009 (see note 1 below)<br>450 | Eligible percentage before March 27, 2009 (from line 310 in Part 3) | F2<br>Eligible expenditures after March 26, 2009 (see note 1 below)<br>452 | Eligible percentage after March 26, 2009 (from line 310a in Part 3) | X<br>Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below) | Y<br>Total number of consecutive weeks of the student's WP (see note 3 below) |
|---|---|---|---|---|---|---|
| 1. | | 10.000 % | 15,562 | 25.000 % | | 17 |
| 2. | | 10.000 % | 15,562 | 25.000 % | | 17 |
| 3. | | 10.000 % | 20,058 | 25.000 % | | 17 |
| 4. | | 10.000 % | 20,058 | 25.000 % | | 17 |

| | G<br>Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below)<br>460 | H<br>Maximum CETC per WP (see note 3 below)<br>462 | I<br>CETC on eligible expenditures (column G or H, whichever is less)<br>470 | J<br>CETC on repayment of government assistance (see note 4 below)<br>480 | K<br>CETC for each WP (column I or column J)<br>490 |
|---|---|---|---|---|---|
| 1. | 3,891 | 3,000 | 3,000 | | 3,000 |
| 2. | 3,891 | 3,000 | 3,000 | | 3,000 |
| 3. | 5,015 | 3,000 | 3,000 | | 3,000 |
| 4. | 5,015 | 3,000 | 3,000 | | 3,000 |

**Ontario co-operative education tax credit** (total of amounts in column K) 500 ..... 12,000 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = ....................... M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

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**Schedule 552**

# Ontario Apprenticeship Training Tax Credit

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro One Remote Communities Inc. | 87083 6269 RC0001 | 2016-12-31 |

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

| **110** Name of person to contact for more information | **120** Telephone number |
|---|---|
| GLENDY CHEUNG | (416) 345-6812 |

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

## Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 1,880,249

**For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:**

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[ 10\,\% \times \left( \frac{\text{amount on line 300} \quad \textbf{minus} \quad 400{,}000}{200{,}000} \right) \right]$$

**Specified percentage** . . . . . **312** 35.000 %

**For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:**

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \quad \textbf{minus} \quad 400{,}000}{200{,}000} \right) \right]$$

**Specified percentage** . . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

| | A Trade code 400 | B Apprenticeship program/trade name 405 | C Name of apprentice 410 |
|---|---|---|---|
| 1. | 309a | Electrician-Construction and Maintenance | [redacted] |
| 2. | 310t | Truck And Coach Technician | [redacted] |
| 3. | 310t | Truck And Coach Technician | [redacted]s |
| 4. | 310t | Truck And Coach Technician | [redacted] |
| 5. | 310t | Truck And Coach Technician | [redacted] |
| 6. | 310t | Truck And Coach Technician | [redacted] |
| 7. | 434a | Powerline Technician | [redacted] |
| 8. | 434a | Powerline Technician | [redacted] |

| | D Original contract or training agreement number 420 | E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425 | F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430 | G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435 |
|---|---|---|---|---|
| 1. | [redacted] | 2014-05-26 | 2016-01-01 | 2016-12-16 |
| 2. | [redacted] | 2012-05-28 | 2016-01-04 | 2016-03-25 |
| 3. | [redacted] | 2014-01-13 | 2016-04-24 | 2016-07-29 |
| 4. | [redacted] | 2014-01-13 | 2016-05-24 | 2016-07-27 |
| 5. | [redacted] | 2014-01-13 | 2016-07-04 | 2016-09-29 |
| 6. | [redacted] | 2014-01-13 | 2016-10-03 | 2016-11-30 |
| 7. | [redacted] | 2013-01-28 | 2016-01-04 | 2016-06-30 |

| | D<br>Original contract or training agreement number<br>420 | E<br>Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1)<br>425 | F<br>Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2)<br>430 | G<br>End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3)<br>435 |
|---|---|---|---|---|
| 8. | [redacted] | 2013-01-28 | 2016-07-04 | 2016-12-23 |

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

## Part 4 – Ontario apprenticeship training tax credit (continued)

| | **H1** Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442 | **H2** Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443 | **I** Maximum credit amount for the tax year (see note 2) 445 |
|---|---|---|---|
| 1. | 350 | | 9,563 |
| 2. | 81 | | 2,213 |
| 3. | 96 | | 2,623 |
| 4. | 64 | | 1,749 |
| 5. | 87 | | 2,377 |
| 6. | 58 | | 1,585 |
| 7. | 178 | | 4,863 |
| 8. | 172 | | 4,699 |

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*) or ($5,000 × H2/365*), whichever applies.
* 366 days, if the tax year includes February 29

| | **J1** Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452 | **J2** Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453 | **K** Eligible expenditures **multiplied** by specified percentage (see note 4) 460 |
|---|---|---|---|
| 1. | 50,440 | | 17,654 |
| 2. | 73,063 | | 25,572 |
| 3. | 94,232 | | 32,981 |
| 4. | 85,659 | | 29,981 |
| 5. | 124,020 | | 43,407 |
| 6. | 88,616 | | 31,016 |
| 7. | 119,680 | | 41,888 |
| 8. | 109,952 | | 38,483 |

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.
For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

| | **L** ATTC on eligible expenditures (lesser of columns I and K) 470 | **M** ATTC on repayment of government assistance (see note 5) 480 | **N** ATTC for each apprentice (column L or M, whichever applies) 490 |
|---|---|---|---|
| 1. | 9,563 | | 9,563 |
| 2. | 2,213 | | 2,213 |
| 3. | 2,623 | | 2,623 |
| 4. | 1,749 | | 1,749 |
| 5. | 2,377 | | 2,377 |
| 6. | 1,585 | | 1,585 |
| 7. | 4,863 | | 4,863 |

| | L<br>ATTC on eligible expenditures<br>(lesser of columns I and K)<br>470 | M<br>ATTC on repayment of<br>government assistance<br>(see note 5)<br>480 | N<br>ATTC for each apprentice<br>(column L or M,<br>whichever applies)<br>490 |
|---|---|---|---|
| 8. | 4,699 | | 4,699 |

**Ontario apprenticeship training tax credit** (total of amounts in column N) 500 29,672 **O**

**Or**, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ____________ x percentage on line 170 in Part 1 ________ % = . . . . . . . . . . . . . . . . ____________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

# DEPRECIATION AND AMORTIZATION EXPENSES
# 2013 TO 2018

Attachment 1: Depreciation and Amortization Expenses 2013 – OEB Chapter 2, Appendix 2-C

Attachment 2: Depreciation and Amortization Expenses 2014 – OEB Chapter 2, Appendix 2-C

Attachment 3: Depreciation and Amortization Expenses 2015 – OEB Chapter 2, Appendix 2-C

Attachment 4: Depreciation and Amortization Expenses 2016 – OEB Chapter 2, Appendix 2-C

Attachment 5: Depreciation and Amortization Expenses 2017 – OEB Chapter 2, Appendix 2-C

Attachment 6: Depreciation and Amortization Expenses 2018 – OEB Chapter 2, Appendix 2-C

# Appendix 2-C
## Depreciation and Amortization Expense
## 2013 (Accounting Standard USGAAP)

**This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B**

| Scenario that applies | Applicable Years and Accounting Standard | Year Reflected in Schedule Below | Accounting Standard Reflected in Schedule Below |
|---|---|---|---|
| Rebasing for the first time with depreciation policy changes made in 2012. | This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Rebasing for the first time with depreciation policy changes made in 2013. ☑ | This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Already rebased with depreciation policy changes in a prior rate application | This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |

| | | Book Values | | | | | | | Service Lives | | | | Depreciation Expense | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Account | Description | Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1] | Less Fully Depreciated [7] | Net Amount of Existing Assets Before Policy Change to be Depreciated | Opening Gross Book Value of Assets Acquired After Policy Change [2] | Less Fully Depreciated [8] | Net Amount of Assets Acquired After Policy Change to be Depreciated | Current Year Additions | Average Remaining Life of Assets Existing Before Policy Change [3] | Depreciation Rate Assets Acquired After Policy Change | Life of Assets Acquired After Policy Change [4] | Depreciation Rate on New Additions | Depreciation Expense on Assets Existing Before Policy Change | Depreciation Expense on Assets Acquired After Policy Change | Depreciation Expense on Current Year Additions [5] | Total Current Year Depreciation Expense | Depreciation Expense per Appendix 2-BA Fixed Assets, Column J | Variance [6] |
| | | a | b | c = a-b | d | e | f = d- e | g | h | i = 1/h | j | k = 1/j | l = c/j was l = c/h | m = f/j | n = g*0.5/j | o = l+m+n | p | q = p-o |
| 1611 | Computer Software (Formally known as Account 1925) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1612 | Land Rights (Formally known as Account 1906) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1615 | Land | | | $ - | | | $ - | | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1620 | Buildings &Fixtures | $ 3,583,639 | -$ 52,478 | $ 3,636,117 | | | $ - | $ 110,891 | | 0.00% | 35.00 | 2.86% | $ 103,889 | $ - | $ 1,584 | $ 105,473 | $ 124,399 | $ 18,926 |
| 1650 | Reservoirs Dams & Water | -$ 79,422 | -$ 79,422 | $ - | | | $ - | | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1665 | Fuel Holders Produce | $ 4,187,261 | | $ 4,187,261 | | | $ - | $ 1,982,200 | | 0.00% | 35.00 | 2.86% | $ 119,636 | $ - | $ 28,317 | $ 147,953 | $ 169,359 | $ 21,406 |
| 1670 | Prime Movers | $ 319,717 | -$ 3,673,133 | $ 3,992,849 | | | $ - | $ 3,190,922 | | 0.00% | 10.00 | 10.00% | $ 399,285 | $ - | $ 159,546 | $ 558,831 | $ 1,120,389 | $ 561,558 |
| 1675 | Generators | $ 5,225,868 | -$ 82,652 | $ 5,308,520 | | | $ - | $ 1,374,135 | | 0.00% | 16.00 | 6.25% | $ 331,783 | $ - | $ 42,942 | $ 374,724 | $ 388,504 | $ 13,780 |
| 1680 | Accessory Electc Equ | $ 1,146,751 | | $ 1,146,751 | | | $ - | $ 1,017,063 | | 0.00% | 17.00 | 5.88% | $ 67,456 | $ - | $ 29,914 | $ 97,370 | $ 145,497 | $ 48,127 |
| 1685 | Misc Power Plant Equ | $ 2,014,172 | -$ 151,369 | $ 2,165,541 | | | $ - | $ 35,011 | | 0.00% | 25.00 | 4.00% | $ 86,622 | $ - | $ 700 | $ 87,322 | $ 98,641 | $ 11,319 |
| 1805 | Land | $ 238,544 | | $ 238,544 | | | $ - | | | 0.00% | 50.00 | 2.00% | $ 4,771 | $ - | $ - | $ 4,771 | $ 5,712 | $ 941 |
| 1806 | L&Rights | $ 165,157 | | $ 165,157 | | | $ - | | | 0.00% | 100.00 | 1.00% | $ 1,652 | $ - | $ - | $ 1,652 | $ 2,271 | $ 619 |
| 1808 | Buildings | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1810 | Leasehold Improvements | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1815 | Transformer Station Equipment >50 kV | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1820 | Distribution Station Equipment <50 kV | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1825 | Storage Battery Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1830 | Poles, Towers & Fixtures | $ 1,702,419 | -$ 17 | $ 1,702,437 | | | $ - | $ 279,003 | | 0.00% | 55.00 | 1.82% | $ 30,953 | $ - | $ 2,536 | $ 33,490 | $ 41,705 | $ 8,215 |
| 1835 | Overhead Conductors & Devices | $ 1,136,584 | -$ 22 | $ 1,136,606 | | | $ - | $ 118,872 | | 0.00% | 50.00 | 2.00% | $ 22,732 | $ - | $ 1,189 | $ 23,921 | $ 31,672 | $ 7,751 |
| 1840 | Underground Conduit | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1845 | Underground Conductors & Devices | $ 64,897 | -$ 19 | $ 64,917 | | | $ - | $ 94,879 | | 0.00% | 30.00 | 3.33% | $ 2,164 | $ - | $ 1,581 | $ 3,745 | $ 5,641 | $ 1,896 |
| 1850 | Line Transformers | $ 1,319,192 | | $ 1,319,192 | | | $ - | | | 0.00% | 35.00 | 2.86% | $ 37,691 | $ - | $ - | $ 37,691 | $ 45,834 | $ 8,143 |
| 1855 | Services (Overhead & Underground) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1860 | Meters | $ 131,366 | -$ 57 | $ 131,423 | | | $ - | $ 214,160 | | 0.00% | 5.00 | 20.00% | $ 26,285 | $ - | $ 21,416 | $ 47,701 | $ 45,472 | -$ 2,229 |
| 1860 | Meters (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1905 | Land | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1908 | Buildings & Fixtures | $ 7,486,020 | | $ 7,486,020 | | | $ - | $ 571,911 | | 0.00% | 40.00 | 2.50% | $ 187,150 | $ - | $ 7,149 | $ 194,299 | $ 180,309 | -$ 13,990 |
| 1910 | Leasehold Improvements | $ 57,718 | | $ 57,718 | | | $ - | | | 0.00% | 10.00 | 10.00% | $ 5,772 | $ - | $ - | $ 5,772 | $ 7,677 | $ 1,905 |
| 1915 | Office Furniture & Equipment (10 years) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1915 | Office Furniture & Equipment (5 & 7 years) | $ 45,536 | | $ 45,536 | | | $ - | | | 0.00% | 7.00 | 14.29% | $ 6,505 | $ - | $ - | $ 6,505 | $ 9,389 | $ 2,884 |
| 1920 | Computer Equipment - Hardware | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 39,268 | | $ 39,268 | | | $ - | | | 0.00% | 5.00 | 20.00% | $ 7,854 | $ - | $ - | $ 7,854 | $ 13,625 | $ 5,771 |
| 1930 | Transportation Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1935 | Stores Equipment | $ 150,892 | | $ 150,892 | | | $ - | | | 0.00% | 8.00 | 12.50% | $ 18,862 | $ - | $ - | $ 18,862 | $ 33,246 | $ 14,384 |
| 1940 | Tools, Shop & Garage Equipment | $ 29,061 | | $ 29,061 | | | $ - | $ 21,224 | | 0.00% | 6.00 | 16.67% | $ 4,844 | $ - | $ 1,769 | $ 6,612 | $ 8,359 | $ 1,747 |
| 1945 | Measurement & Testing Equipment | $ 39,041 | | $ 39,041 | | | $ - | $ 57,030 | | 0.00% | 5.00 | 20.00% | $ 7,808 | $ - | $ 5,703 | $ 13,511 | $ 16,449 | $ 2,938 |
| 1950 | Power Operated Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1955 | Communications Equipment | -$ 10,405 | -$ 10,405 | $ - | | | $ - | | | 0.00% | 7.00 | 14.29% | $ - | $ - | $ - | $ - | $ 687 | $ 687 |
| 1955 | Communication Equipment (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1960 | Miscellaneous Equipment | $ 188,891 | | $ 188,891 | | | $ - | $ 136,214 | | 0.00% | 5.00 | 20.00% | $ 37,778 | $ - | $ 13,621 | $ 51,400 | $ 68,658 | $ 17,258 |
| 1970 | Load Management Controls Customer Premises | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1975 | Load Management Controls Utility Premises | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1980 | System Supervisor Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1985 | Miscellaneous Fixed Assets | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1990 | Other Tangible Property | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1995 | Contributions & Grants | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| A | Maj Rollup Acc Dep Suspense | -$ 343,689 | | -$ 343,689 | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| B | Acc Dep - Contra for Group Retirement | $ 172,061 | | $ 172,061 | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| C | Suspense/Conversion/Error | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| | **Total** | **$ 29,010,541** | **-$ 4,049,575** | **$ 33,060,115** | **$ -** | **$ -** | **$ -** | **$ 9,203,515** | | | | | **$ 1,511,490** | **$ -** | **$ 317,967** | **$ 1,829,458** | **$ 2,563,495** | **$ 734,037** |

**General:** Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial

**Notes:**

1. until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. the prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

**Appendix 2-C**
**Depreciation and Amortization Expense**
**2014 (Accounting Standard USGAAP)**

**This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B**

| Scenario that applies | Applicable Years and Accounting Standard | Year Reflected in Schedule Below | Accounting Standard Reflected in Schedule Below |
|---|---|---|---|
| Rebasing for the first time with depreciation policy changes made in 2012. | This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Rebasing for the first time with depreciation policy changes made in 2013. ☑ | This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Already rebased with depreciation policy changes in a prior rate application | This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |

| | | Book Values | | | | | | | Service Lives | | | | Depreciation Expense | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Account | Description | Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1] | Less Fully Depreciated [7] | Net Amount of Existing Assets Before Policy Change to be Depreciated | Opening Gross Book Value of Assets Acquired After Policy Change [2] | Less Fully Depreciated [8] | Net Amount of Assets Acquired After Policy Change to be Depreciated | Current Year Additions | Average Remaining Life of Assets Existing Before Policy Change [3] | Depreciation Rate Assets Acquired After Policy Change | Life of Assets Acquired After Policy Change [4] | Depreciation Rate on New Additions | Depreciation Expense on Assets Existing Before Policy Change | Depreciation Expense on Assets Acquired After Policy Change | Depreciation Expense on Current Year Additions [5] | Total Current Year Depreciation Expense | Depreciation Expense per Appendix 2-BA Fixed Assets, Column J | Variance [6] |
| | | a | b | c = a-b | d | e | f = d- e | g | h | i = 1/h | j | k = 1/j | l = c/j was l = c/h | m = f/j | n = g*0.5/j | o = l+m+n | p | q = p-o |
| 1611 | Computer Software (Formally known as Account 1925) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1612 | Land Rights (Formally known as Account 1906) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1615 | Land | | | $ - | | | $ - | | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1620 | Buildings &Fixtures | $ 3,147,605 | | $ 3,147,605 | | | $ - | | | 0.00% | 35.00 | 2.86% | $ 89,932 | $ - | $ - | $ 89,932 | $ 123,387 | $ 33,455 |
| 1650 | Reservoirs Dams & Water | | | $ - | | | $ - | | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1665 | Fuel Holders Produce | $ 5,893,849 | | $ 5,893,849 | | | $ - | $ 1,234,762 | | 0.00% | 35.00 | 2.86% | $ 168,396 | $ - | $ 17,639 | $ 186,035 | $ 206,904 | $ 20,869 |
| 1670 | Prime Movers | $ 4,759,973 | -$ 2,682,164 | $ 7,442,137 | | | $ - | $ 1,853,579 | | 0.00% | 10.00 | 10.00% | $ 744,214 | $ - | $ 92,679 | $ 836,893 | $ 1,044,464 | $ 207,571 |
| 1675 | Generators | $ 4,306,403 | -$ 427,177 | $ 4,733,580 | | | $ - | $ 618,691 | | 0.00% | 16.00 | 6.25% | $ 295,849 | $ - | $ 19,334 | $ 315,183 | $ 411,702 | $ 96,519 |
| 1680 | Accessory Electc Equ | $ 1,648,731 | -$ 28,014 | $ 1,676,745 | | | $ - | $ 323,546 | | 0.00% | 17.00 | 5.88% | $ 98,632 | $ - | $ 9,516 | $ 108,148 | $ 142,172 | $ 34,024 |
| 1685 | Misc Power Plant Equ | $ 1,993,887 | -$ 13,948 | $ 2,007,835 | | | $ - | $ 273,666 | | 0.00% | 25.00 | 4.00% | $ 80,313 | $ - | $ 5,473 | $ 85,787 | $ 106,123 | $ 20,336 |
| 1805 | Land | $ 198,837 | | $ 198,837 | | | $ - | | | 0.00% | 50.00 | 2.00% | $ 3,977 | $ - | $ - | $ 3,977 | $ 5,712 | $ 1,735 |
| 1806 | L&Rights | $ 171,220 | | $ 171,220 | | | $ - | | | 0.00% | 100.00 | 1.00% | $ 1,712 | $ - | $ - | $ 1,712 | $ 2,271 | $ 559 |
| 1808 | Buildings | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1810 | Leasehold Improvements | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1815 | Transformer Station Equipment >50 kV | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1820 | Distribution Station Equipment <50 kV | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1825 | Storage Battery Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1830 | Poles, Towers & Fixtures | $ 1,956,550 | -$ 150 | $ 1,956,700 | | | $ - | $ 455,279 | | 0.00% | 55.00 | 1.82% | $ 35,576 | $ - | $ 4,139 | $ 39,715 | $ 48,533 | $ 8,818 |
| 1835 | Overhead Conductors & Devices | $ 1,235,495 | -$ 22 | $ 1,235,517 | | | $ - | $ 259,132 | | 0.00% | 50.00 | 2.00% | $ 24,710 | $ - | $ 2,591 | $ 27,302 | $ 34,026 | $ 6,724 |
| 1840 | Underground Conduit | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1845 | Underground Conductors & Devices | $ 64,271 | -$ 23 | $ 64,294 | | | $ - | $ 106,185 | | 0.00% | 30.00 | 3.33% | $ 2,143 | $ - | $ 1,770 | $ 3,913 | $ 7,444 | $ 3,531 |
| 1850 | Line Transformers | $ 1,370,862 | -$ 11 | $ 1,370,873 | | | $ - | $ 201,371 | | 0.00% | 35.00 | 2.86% | $ 39,168 | $ - | $ 2,877 | $ 42,045 | $ 49,593 | $ 7,548 |
| 1855 | Services (Overhead & Underground) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1860 | Meters | $ 361,414 | -$ 57 | $ 361,471 | | | $ - | $ 40,166 | | 0.00% | 5.00 | 20.00% | $ 72,294 | $ - | $ 4,017 | $ 76,311 | $ 35,721 | -$ 40,590 |
| 1860 | Meters (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1905 | Land | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1908 | Buildings & Fixtures | $ 8,004,192 | | $ 8,004,192 | | | $ - | $ 368,887 | | 0.00% | 40.00 | 2.50% | $ 200,105 | $ - | $ 4,611 | $ 204,716 | $ 189,482 | -$ 15,234 |
| 1910 | Leasehold Improvements | $ 50,042 | | $ 50,042 | | | $ - | $ 47,121 | | 0.00% | 10.00 | 10.00% | $ 5,004 | $ - | $ 2,356 | $ 7,360 | $ 7,677 | $ 317 |
| 1915 | Office Furniture & Equipment (10 years) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1915 | Office Furniture & Equipment (5 & 7 years) | $ 36,147 | | $ 36,147 | | | $ - | $ 21,700 | | 0.00% | 7.00 | 14.29% | $ 5,164 | $ - | $ 1,550 | $ 6,714 | $ 10,004 | $ 3,290 |
| 1920 | Computer Equipment - Hardware | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 26,667 | | $ 26,667 | | | $ - | | | 0.00% | 5.00 | 20.00% | $ 5,333 | $ - | $ - | $ 5,333 | $ 11,849 | $ 6,516 |
| 1930 | Transportation Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1935 | Stores Equipment | $ 117,645 | | $ 117,645 | | | $ - | | | 0.00% | 8.00 | 12.50% | $ 14,706 | $ - | $ - | $ 14,706 | $ 28,971 | $ 14,265 |
| 1940 | Tools, Shop & Garage Equipment | $ 41,842 | | $ 41,842 | | | $ - | $ 26,784 | | 0.00% | 6.00 | 16.67% | $ 6,974 | $ - | $ 2,232 | $ 9,206 | $ 12,360 | $ 3,154 |
| 1945 | Measurement & Testing Equipment | $ 79,622 | | $ 79,622 | | | $ - | $ 19,962 | | 0.00% | 5.00 | 20.00% | $ 15,924 | $ - | $ 1,996 | $ 17,921 | $ 23,619 | $ 5,698 |
| 1950 | Power Operated Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1955 | Communications Equipment | -$ 6,414 | -$ 6,414 | -$ 0 | | | $ - | | | 0.00% | 7.00 | 14.29% | -$ 0 | $ - | $ - | -$ 0 | $ 687 | $ 687 |
| 1955 | Communication Equipment (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1960 | Miscellaneous Equipment | $ 256,710 | | $ 256,710 | | | $ - | $ 118,868 | | 0.00% | 5.00 | 20.00% | $ 51,342 | $ - | $ 11,887 | $ 63,229 | $ 91,350 | $ 28,121 |
| 1970 | Load Management Controls Customer Premises | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1975 | Load Management Controls Utility Premises | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1980 | System Supervisor Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1985 | Miscellaneous Fixed Assets | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1990 | Other Tangible Property | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1995 | Contributions & Grants | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| A | Maj Rollup Acc Dep Suspense | -$ 240,316 | | -$ 240,316 | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| B | Acc Dep - Contra for Group Retirement | $ 172,061 | | $ 172,061 | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| C | Suspense/Conversion/Error | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| | **Total** | **$ 35,647,295** | **-$ 3,157,979** | **$ 38,805,274** | **$ -** | **$ -** | **$ -** | **$ 5,969,699** | | | | | **$ 1,961,468** | **$ -** | **$ 184,667** | **$ 2,146,135** | **$ 2,594,051** | **$ 447,916** |

**General:** Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial

**Notes:**

1. until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. the prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

## Appendix 2-C
## Depreciation and Amortization Expense
## 2015 (Accounting Standard USGAAP)

**This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B**

| Scenario that applies | Applicable Years and Accounting Standard | Year Reflected in Schedule Below | Accounting Standard Reflected in Schedule Below |
|---|---|---|---|
| Rebasing for the first time with depreciation policy changes made in 2012 | This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Rebasing for the first time with depreciation policy changes made in 2013 | This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Already rebased with depreciation policy changes in a prior rate application | This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |

| | | Book Values | | | | | | | Service Lives | | | | Depreciation Expense | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Account | Description | Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1] | Less Fully Depreciated [7] | Net Amount of Existing Assets Before Policy Change to be Depreciated | Opening Gross Book Value of Assets Acquired After Policy Change [2] | Less Fully Depreciated [8] | Net Amount of Assets Acquired After Policy Change to be Depreciated | Current Year Additions | Average Remaining Life of Assets Existing Before Policy Change [3] | Depreciation Rate Assets Acquired After Policy Change | Life of Assets Acquired After Policy Change [4] | Depreciation Rate on New Additions | Depreciation Expense on Assets Existing Before Policy Change | Depreciation Expense on Assets Acquired After Policy Change | Depreciation Expense on Current Year Additions [5] | Total Current Year Depreciation Expense | Depreciation Expense per Appendix 2-BA Fixed Assets, Column J | Variance [6] |
| | | a | b | c = a-b | d | e | f = d- e | g | h | i = 1/h | j | k = 1/j | l = c/j was l = c/h | m = f/j | n = g*0.5/j | o = l+m+n | p | q = p-o |
| 1611 | Computer Software (Formally known as Account 1925) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1612 | Land Rights (Formally known as Account 1906) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1615 | Land | | | $ - | | | $ - | | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1620 | Buildings &Fixtures | $ 3,024,218 | | $ 3,024,218 | | | $ - | $ 385,060 | | 0.00% | 35.00 | 2.86% | $ 86,406 | $ - | $ 5,501 | $ 91,907 | $ 132,687 | $ 40,780 |
| 1650 | Reservoirs Dams & Water | | | $ - | | | $ - | | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1665 | Fuel Holders Produce | $ 6,921,707 | | $ 6,921,707 | | | $ - | | | 0.00% | 35.00 | 2.86% | $ 197,763 | $ - | $ - | $ 197,763 | $ 212,150 | $ 14,387 |
| 1670 | Prime Movers | $ 5,570,288 | -$ 2,889,966 | $ 8,460,254 | | | $ - | $ 973,391 | | 0.00% | 10.00 | 10.00% | $ 846,025 | $ - | $ 48,670 | $ 894,695 | $ 1,070,467 | $ 175,772 |
| 1675 | Generators | $ 4,513,392 | -$ 471,859 | $ 4,985,251 | | | $ - | $ 822,035 | | 0.00% | 16.00 | 6.25% | $ 311,578 | $ - | $ 25,689 | $ 337,267 | $ 421,061 | $ 83,794 |
| 1680 | Accessory Electc Equ | $ 1,830,105 | -$ 31,753 | $ 1,861,858 | | | $ - | $ 95 | | 0.00% | 17.00 | 5.88% | $ 109,521 | $ - | $ 3 | $ 109,524 | $ 150,977 | $ 41,453 |
| 1685 | Misc Power Plant Equ | $ 2,161,430 | -$ 14,046 | $ 2,175,476 | | | $ - | $ 4,560 | | 0.00% | 25.00 | 4.00% | $ 87,019 | $ - | $ 91 | $ 87,110 | $ 109,075 | $ 21,965 |
| 1805 | Land | $ 193,125 | | $ 193,125 | | | $ - | | | 0.00% | 50.00 | 2.00% | $ 3,863 | $ - | $ - | $ 3,863 | $ 5,712 | $ 1,850 |
| 1806 | L&Rights | $ 168,949 | | $ 168,949 | | | $ - | | | 0.00% | 100.00 | 1.00% | $ 1,689 | $ - | $ - | $ 1,689 | $ 2,271 | $ 582 |
| 1808 | Buildings | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1810 | Leasehold Improvements | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1815 | Transformer Station Equipment >50 kV | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1820 | Distribution Station Equipment <50 kV | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1825 | Storage Battery Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1830 | Poles, Towers & Fixtures | $ 2,363,296 | -$ 165 | $ 2,363,461 | | | $ - | $ 79,105 | | 0.00% | 55.00 | 1.82% | $ 42,972 | $ - | $ 719 | $ 43,691 | $ 50,610 | $ 6,919 |
| 1835 | Overhead Conductors & Devices | $ 1,460,601 | -$ 22 | $ 1,460,623 | | | $ - | $ 139,846 | | 0.00% | 50.00 | 2.00% | $ 29,212 | $ - | $ 1,398 | $ 30,611 | $ 37,146 | $ 6,535 |
| 1840 | Underground Conduit | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1845 | Underground Conductors & Devices | $ 163,012 | -$ 73 | $ 163,085 | | | $ - | | | 0.00% | 30.00 | 3.33% | $ 5,436 | $ - | $ - | $ 5,436 | $ 7,701 | $ 2,265 |
| 1850 | Line Transformers | $ 1,511,300 | -$ 18 | $ 1,511,318 | | | $ - | $ 120,118 | | 0.00% | 35.00 | 2.86% | $ 43,181 | $ - | $ 1,716 | $ 44,896 | $ 51,922 | $ 7,026 |
| 1855 | Services (Overhead & Underground) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1860 | Meters | $ 365,859 | -$ 57 | $ 365,916 | | | $ - | $ 33,655 | | 0.00% | 5.00 | 20.00% | $ 73,183 | $ - | $ 3,365 | $ 76,549 | $ 38,233 | -$ 38,316 |
| 1860 | Meters (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1905 | Land | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1908 | Buildings & Fixtures | $ 8,183,597 | | $ 8,183,597 | | | $ - | $ 437,828 | | 0.00% | 40.00 | 2.50% | $ 204,590 | $ - | $ 5,473 | $ 210,063 | $ 200,421 | -$ 9,642 |
| 1910 | Leasehold Improvements | $ 89,486 | | $ 89,486 | | | $ - | | | 0.00% | 10.00 | 10.00% | $ 8,949 | $ - | $ - | $ 8,949 | $ 15,650 | $ 6,701 |
| 1915 | Office Furniture & Equipment (10 years) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1915 | Office Furniture & Equipment (5 & 7 years) | $ 47,843 | | $ 47,843 | | | $ - | | | 0.00% | 7.00 | 14.29% | $ 6,835 | $ - | $ - | $ 6,835 | $ 10,775 | $ 3,940 |
| 1920 | Computer Equipment - Hardware | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 14,818 | | $ 14,818 | | | $ - | | | 0.00% | 5.00 | 20.00% | $ 2,964 | $ - | $ - | $ 2,964 | $ 9,497 | $ 6,533 |
| 1930 | Transportation Equipment | | | $ - | | | $ - | $ 3,488 | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1935 | Stores Equipment | $ 88,674 | | $ 88,674 | | | $ - | | | 0.00% | 8.00 | 12.50% | $ 11,084 | $ - | $ - | $ 11,084 | $ 22,325 | $ 11,241 |
| 1940 | Tools, Shop & Garage Equipment | $ 56,266 | | $ 56,266 | | | $ - | $ 4,329 | | 0.00% | 6.00 | 16.67% | $ 9,378 | $ - | $ 361 | $ 9,738 | $ 14,446 | $ 4,708 |
| 1945 | Measurement & Testing Equipment | $ 75,965 | | $ 75,965 | | | $ - | $ 9,735 | | 0.00% | 5.00 | 20.00% | $ 15,193 | $ - | $ 974 | $ 16,167 | $ 25,189 | $ 9,022 |
| 1950 | Power Operated Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1955 | Communications Equipment | -$ 7,101 | -$ 7,101 | -$ 0 | | | $ - | | | 0.00% | 7.00 | 14.29% | -$ 0 | $ - | $ - | -$ 0 | $ 687 | $ 687 |
| 1955 | Communication Equipment (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1960 | Miscellaneous Equipment | $ 284,228 | | $ 284,228 | | | $ - | $ 264,539 | | 0.00% | 5.00 | 20.00% | $ 56,846 | $ - | $ 26,454 | $ 83,300 | $ 122,464 | $ 39,164 |
| 1970 | Load Management Controls Customer Premises | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1975 | Load Management Controls Utility Premises | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1980 | System Supervisor Equipment | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1985 | Miscellaneous Fixed Assets | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1990 | Other Tangible Property | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1995 | Contributions & Grants | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| A | Maj Rollup Acc Dep Suspense | -$ 240,316 | | -$ 240,316 | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| B | Acc Dep - Contra for Group Retirement | $ 172,061 | | $ 172,061 | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| C | Suspense/Conversion/Error | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| | **Total** | **$ 39,012,803** | **-$ 3,415,059** | **$ 42,427,862** | **$ -** | **$ -** | **$ -** | **$ 3,277,784** | | | | | **$ 2,153,687** | **$ -** | **$ 120,413** | **$ 2,274,100** | **$ 2,711,466** | **$ 437,366** |

**General:** Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial

**Notes:**

1. until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

**Appendix 2-C**
**Depreciation and Amortization Expense**
**2016 (Accounting Standard USGAAP)**

**This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B**

| Scenario that applies | Applicable Years and Accounting Standard | Year Reflected in Schedule Below | Accounting Standard Reflected in Schedule Below |
|---|---|---|---|
| Rebasing for the first time with depreciation policy changes made in 2012. | This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Rebasing for the first time with depreciation policy changes made in 2013. ☑ | This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Already rebased with depreciation policy changes in a prior rate application | This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |

| | | Book Values | | | | | | | Service Lives | | | | Depreciation Expense | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Account | Description | Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1] | Less Fully Depreciated [7] | Net Amount of Existing Assets Before Policy Change to be Depreciated | Opening Gross Book Value of Assets Acquired After Policy Change [2] | Less Fully Depreciated [8] | Net Amount of Assets Acquired After Policy Change to be Depreciated | Current Year Additions | Average Remaining Life of Assets Existing Before Policy Change [3] | Depreciation Rate Assets Acquired After Policy Change | Life of Assets Acquired After Policy Change [4] | Depreciation Rate on New Additions | Depreciation Expense on Assets Existing Before Policy Change | Depreciation Expense on Assets Acquired After Policy Change | Depreciation Expense on Current Year Additions [5] | Total Current Year Depreciation Expense | Depreciation Expense per Appendix 2-BA Fixed Assets, Column J | Variance [6] |
| | | a | b | c = a-b | d | e | f = d- e | g | h | i = 1/h | j | k = 1/j | l = c/j was l = c/h | m = f/j | n = g*0.5/j | o = l+m+n | p | q = p-o |
| 1611 | Computer Software (Formally known as Account 1925) | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1612 | Land Rights (Formally known as Account 1906) | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1615 | Land | $ - | | $ - | | | $ - | $ 211,340 | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1620 | Buildings &Fixtures | $ 3,276,591 | | $ 3,276,591 | | | $ - | | | 0.00% | 35.00 | 2.86% | $ 93,617 | $ - | $ - | $ 93,617 | $ 137,030 | $ 43,413 |
| 1650 | Reservoirs Dams & Water | $ - | | $ - | | | $ - | | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1665 | Fuel Holders Produce | $ 6,709,557 | | $ 6,709,557 | | | $ - | | | 0.00% | 35.00 | 2.86% | $ 191,702 | $ - | $ - | $ 191,702 | $ 207,882 | $ 16,180 |
| 1670 | Prime Movers | $ 5,473,412 | -$ 3,093,416 | $ 8,566,828 | | | $ - | $ 2,150,627 | | 0.00% | 10.00 | 10.00% | $ 856,683 | $ - | $ 107,531 | $ 964,214 | $ 1,079,006 | $ 114,792 |
| 1675 | Generators | $ 4,914,366 | -$ 527,894 | $ 5,442,260 | | | $ - | $ 716,876 | | 0.00% | 16.00 | 6.25% | $ 340,141 | $ - | $ 22,402 | $ 362,544 | $ 420,843 | $ 58,299 |
| 1680 | Accessory Electc Equ | $ 1,679,223 | -$ 35,795 | $ 1,715,018 | | | $ - | | | 0.00% | 17.00 | 5.88% | $ 100,883 | $ - | $ - | $ 100,883 | $ 150,977 | $ 50,094 |
| 1685 | Misc Power Plant Equ | $ 2,056,915 | -$ 14,451 | $ 2,071,366 | | | $ - | | | 0.00% | 25.00 | 4.00% | $ 82,855 | $ - | $ - | $ 82,855 | $ 109,075 | $ 26,220 |
| 1805 | Land | $ 187,413 | | $ 187,413 | | | $ - | | | 0.00% | 50.00 | 2.00% | $ 3,748 | $ - | $ - | $ 3,748 | $ 5,712 | $ 1,964 |
| 1806 | L&Rights | $ 166,678 | | $ 166,678 | | | $ - | | | 0.00% | 100.00 | 1.00% | $ 1,667 | $ - | $ - | $ 1,667 | $ 2,271 | $ 604 |
| 1808 | Buildings | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1810 | Leasehold Improvements | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1815 | Transformer Station Equipment >50 kV | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1820 | Distribution Station Equipment <50 kV | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1825 | Storage Battery Equipment | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1830 | Poles, Towers & Fixtures | $ 2,365,241 | -$ 181 | $ 2,365,422 | | | $ - | $ 293,078 | | 0.00% | 55.00 | 1.82% | $ 43,008 | $ - | $ 2,664 | $ 45,672 | $ 53,920 | $ 8,248 |
| 1835 | Overhead Conductors & Devices | $ 1,616,400 | -$ 22 | $ 1,616,422 | | | $ - | $ 223,571 | | 0.00% | 50.00 | 2.00% | $ 32,328 | $ - | $ 2,236 | $ 34,564 | $ 42,713 | $ 8,149 |
| 1840 | Underground Conduit | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1845 | Underground Conductors & Devices | $ 155,311 | -$ 159 | $ 155,470 | | | $ - | | | 0.00% | 30.00 | 3.33% | $ 5,182 | $ - | $ - | $ 5,182 | $ 7,701 | $ 2,519 |
| 1850 | Line Transformers | $ 1,552,857 | -$ 25 | $ 1,552,882 | | | $ - | $ 75,044 | | 0.00% | 35.00 | 2.86% | $ 44,368 | $ - | $ 1,072 | $ 45,440 | $ 53,207 | $ 7,767 |
| 1855 | Services (Overhead & Underground) | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1860 | Meters | $ 361,281 | -$ 63 | $ 361,344 | | | $ - | $ 74,092 | | 0.00% | 5.00 | 20.00% | $ 72,269 | $ - | $ 7,409 | $ 79,678 | $ 41,563 | -$ 38,115 |
| 1860 | Meters (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1905 | Land | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1908 | Buildings & Fixtures | $ 8,421,004 | | $ 8,421,004 | | | $ - | $ 801,442 | | 0.00% | 40.00 | 2.50% | $ 210,525 | $ - | $ 10,018 | $ 220,543 | $ 209,500 | -$ 11,043 |
| 1910 | Leasehold Improvements | $ 73,836 | | $ 73,836 | | | $ - | | | 0.00% | 10.00 | 10.00% | $ 7,384 | $ - | $ - | $ 7,384 | $ 12,993 | $ 5,609 |
| 1915 | Office Furniture & Equipment (10 years) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1915 | Office Furniture & Equipment (5 & 7 years) | $ 37,068 | | $ 37,068 | | | $ - | | | 0.00% | 7.00 | 14.29% | $ 5,295 | $ - | $ - | $ 5,295 | $ 10,775 | $ 5,480 |
| 1920 | Computer Equipment - Hardware | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 5,321 | | $ 5,321 | | | $ - | | | 0.00% | 5.00 | 20.00% | $ 1,064 | $ - | $ - | $ 1,064 | $ 4,083 | $ 3,019 |
| 1930 | Transportation Equipment | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1935 | Stores Equipment | $ 66,349 | | $ 66,349 | | | $ - | | | 0.00% | 8.00 | 12.50% | $ 8,294 | $ - | $ - | $ 8,294 | $ 18,844 | $ 10,550 |
| 1940 | Tools, Shop & Garage Equipment | $ 46,149 | | $ 46,149 | | | $ - | $ 36,445 | | 0.00% | 6.00 | 16.67% | $ 7,692 | $ - | $ 3,037 | $ 10,729 | $ 17,337 | $ 6,608 |
| 1945 | Measurement & Testing Equipment | $ 60,511 | | $ 60,511 | | | $ - | | | 0.00% | 5.00 | 20.00% | $ 12,102 | $ - | $ - | $ 12,102 | $ 23,962 | $ 11,860 |
| 1950 | Power Operated Equipment | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1955 | Communications Equipment | -$ 7,788 | -$ 7,788 | $ 0 | | | $ - | | | 0.00% | 7.00 | 14.29% | $ 0 | $ - | $ - | $ 0 | $ 687 | $ 687 |
| 1955 | Communication Equipment (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1960 | Miscellaneous Equipment | $ 429,791 | | $ 429,791 | | | $ - | $ 73,742 | | 0.00% | 5.00 | 20.00% | $ 85,958 | $ - | $ 7,374 | $ 93,332 | $ 141,025 | $ 47,693 |
| 1970 | Load Management Controls Customer Premises | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1975 | Load Management Controls Utility Premises | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1980 | System Supervisor Equipment | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1985 | Miscellaneous Fixed Assets | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1990 | Other Tangible Property | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1995 | Contributions & Grants | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| A | Maj Rollup Acc Dep Suspense | -$ 240,316 | | -$ 240,316 | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| B | Acc Dep - Contra for Group Retirement | $ 172,061 | | $ 172,061 | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| C | Suspense/Conversion/Error | $ - | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| | **Total** | **$ 39,579,231** | **-$ 3,679,791** | **$ 43,259,022** | **$ -** | **$ -** | **$ -** | **$ 4,656,257** | | | | | **$ 2,206,765** | **$ -** | **$ 163,744** | **$ 2,370,509** | **$ 2,751,106** | **$ 380,597** |

**General:** Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial

**Notes:**

1. until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. the prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

**Appendix 2-C**
**Depreciation and Amortization Expense**
**2017 (Accounting Standard USGAAP)**

**This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B**

| Scenario that applies | Applicable Years and Accounting Standard | Year Reflected in Schedule Below | Accounting Standard Reflected in Schedule Below |
|---|---|---|---|
| Rebasing for the first time with depreciation policy changes made in 2012. | This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Rebasing for the first time with depreciation policy changes made in 2013. ☑ | This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Already rebased with depreciation policy changes in a prior rate application | This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |

| | | Book Values | | | | | | | Service Lives | | | | Depreciation Expense | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Account | Description | Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1] | Less Fully Depreciated [7] | Net Amount of Existing Assets Before Policy Change to be Depreciated | Opening Gross Book Value of Assets Acquired After Policy Change [2] | Less Fully Depreciated [8] | Net Amount of Assets Acquired After Policy Change to be Depreciated | Current Year Additions | Average Remaining Life of Assets Existing Before Policy Change [3] | Depreciation Rate Assets Acquired After Policy Change | Life of Assets Acquired After Policy Change [4] | Depreciation Rate on New Additions | Depreciation Expense on Assets Existing Before Policy Change | Depreciation Expense on Assets Acquired After Policy Change | Depreciation Expense on Current Year Additions [5] | Total Current Year Depreciation Expense | Depreciation Expense per Appendix 2-BA Fixed Assets, Column J | Variance [6] |
| | | a | b | c = a-b | d | e | f = d- e | g | h | i = 1/h | j | k = 1/j | l = c/j was l = c/h | m = f/j | n = g*0.5/j | o = l+m+n | p | q = p-o |
| 1611 | Computer Software (Formally known as Account 1925) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1612 | Land Rights (Formally known as Account 1906) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1615 | Land | $ - | | $ - | | | $ - | $ - | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1620 | Buildings &Fixtures | $ 3,350,901 | | $ 3,350,901 | | | $ - | $ 13,760 | | 0.00% | 35.00 | 2.86% | $ 95,740 | $ - | $ 197 | $ 95,937 | $ 140,158 | $ 44,221 |
| 1650 | Reservoirs Dams & Water | $ - | | $ - | | | $ - | $ 206,000 | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | $ 29,429 | $ 29,429 |
| 1665 | Fuel Holders Produce | $ 6,501,675 | | $ 6,501,675 | | | $ - | $ 663,960 | | 0.00% | 35.00 | 2.86% | $ 185,762 | $ - | $ 9,485 | $ 195,247 | $ 212,862 | $ 17,615 |
| 1670 | Prime Movers | $ 6,108,533 | -$ 3,093,416 | $ 9,201,949 | | | $ - | $ 293,963 | | 0.00% | 10.00 | 10.00% | $ 920,195 | $ - | $ 14,698 | $ 934,893 | $ 1,145,586 | $ 210,693 |
| 1675 | Generators | $ 5,064,899 | -$ 527,894 | $ 5,592,793 | | | $ - | $ 139,268 | | 0.00% | 16.00 | 6.25% | $ 349,550 | $ - | $ 4,352 | $ 353,902 | $ 402,004 | $ 48,102 |
| 1680 | Accessory Electc Equ | $ 1,528,246 | -$ 35,795 | $ 1,564,041 | | | $ - | $ 275,300 | | 0.00% | 17.00 | 5.88% | $ 92,002 | $ - | $ 8,097 | $ 100,099 | $ 158,465 | $ 58,366 |
| 1685 | Misc Power Plant Equ | $ 1,947,840 | -$ 14,451 | $ 1,962,291 | | | $ - | $ 244,400 | | 0.00% | 25.00 | 4.00% | $ 78,492 | $ - | $ 4,888 | $ 83,380 | $ 131,722 | $ 48,342 |
| 1805 | Land | $ 181,701 | | $ 181,701 | | | $ - | $ - | | 0.00% | 50.00 | 2.00% | $ 3,634 | $ - | $ - | $ 3,634 | $ 5,712 | $ 2,078 |
| 1806 | L&Rights | $ 164,407 | | $ 164,407 | | | $ - | $ - | | 0.00% | 100.00 | 1.00% | $ 1,644 | $ - | $ - | $ 1,644 | $ 2,271 | $ 627 |
| 1808 | Buildings | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1810 | Leasehold Improvements | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1815 | Transformer Station Equipment >50 kV | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1820 | Distribution Station Equipment <50 kV | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1825 | Storage Battery Equipment | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1830 | Poles, Towers & Fixtures | $ 2,604,399 | -$ 181 | $ 2,604,580 | | | $ - | $ 331,289 | | 0.00% | 55.00 | 1.82% | $ 47,356 | $ - | $ 3,012 | $ 50,368 | $ 58,452 | $ 8,084 |
| 1835 | Overhead Conductors & Devices | $ 1,797,258 | -$ 22 | $ 1,797,280 | | | $ - | $ 236,538 | | 0.00% | 50.00 | 2.00% | $ 35,946 | $ - | $ 2,365 | $ 38,311 | $ 45,582 | $ 7,271 |
| 1840 | Underground Conduit | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1845 | Underground Conductors & Devices | $ 147,610 | -$ 159 | $ 147,769 | | | $ - | $ - | | 0.00% | 30.00 | 3.33% | $ 4,926 | $ - | $ - | $ 4,926 | $ 7,701 | $ 2,775 |
| 1850 | Line Transformers | $ 1,574,350 | -$ 25 | $ 1,574,375 | | | $ - | $ 152,081 | | 0.00% | 35.00 | 2.86% | $ 44,982 | $ - | $ 2,173 | $ 47,155 | $ 55,779 | $ 8,624 |
| 1855 | Services (Overhead & Underground) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1860 | Meters | $ 393,810 | -$ 63 | $ 393,873 | | | $ - | $ 56,487 | | 0.00% | 5.00 | 20.00% | $ 78,775 | $ - | $ 5,649 | $ 84,423 | $ 43,756 | -$ 40,667 |
| 1860 | Meters (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1905 | Land | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1908 | Buildings & Fixtures | $ 9,012,946 | | $ 9,012,946 | | | $ - | $ 818,452 | | 0.00% | 40.00 | 2.50% | $ 225,324 | $ - | $ 10,231 | $ 235,554 | $ 225,375 | -$ 10,179 |
| 1910 | Leasehold Improvements | $ 60,843 | | $ 60,843 | | | $ - | $ - | | 0.00% | 10.00 | 10.00% | $ 6,084 | $ - | $ - | $ 6,084 | $ 12,993 | $ 6,909 |
| 1915-A | Office Furniture & Equipment (10 years) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1915 | Office Furniture & Equipment (5 & 7 years) | $ 26,293 | | $ 26,293 | | | $ - | $ 17,500 | | 0.00% | 7.00 | 14.29% | $ 3,756 | $ - | $ 1,250 | $ 5,006 | $ 8,998 | $ 3,992 |
| 1920-A | Computer Equipment - Hardware | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1920-B | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 1,238 | | $ 1,238 | | | $ - | $ 8,750 | | 0.00% | 5.00 | 20.00% | $ 248 | $ - | $ 875 | $ 1,123 | $ 1,238 | $ 115 |
| 1930 | Transportation Equipment | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1935 | Stores Equipment | $ 47,505 | | $ 47,505 | | | $ - | $ 26,250 | | 0.00% | 8.00 | 12.50% | $ 5,938 | $ - | $ 1,641 | $ 7,579 | $ 17,859 | $ 10,280 |
| 1940 | Tools, Shop & Garage Equipment | $ 65,257 | | $ 65,257 | | | $ - | $ - | | 0.00% | 6.00 | 16.67% | $ 10,876 | $ - | $ - | $ 10,876 | $ 17,544 | $ 6,668 |
| 1945 | Measurement & Testing Equipment | $ 36,549 | | $ 36,549 | | | $ - | $ 21,000 | | 0.00% | 5.00 | 20.00% | $ 7,310 | $ - | $ 2,100 | $ 9,410 | $ 21,634 | $ 12,224 |
| 1950 | Power Operated Equipment | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1955 | Communications Equipment | -$ 8,475 | -$ 7,788 | -$ 687 | | | $ - | $ - | | 0.00% | 7.00 | 14.29% | -$ 98 | $ - | $ - | -$ 98 | $ 687 | $ 785 |
| 1955 | Communication Equipment (Smart Meters) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1960 | Miscellaneous Equipment | $ 362,508 | | $ 362,508 | | | $ - | $ 101,500 | | 0.00% | 5.00 | 20.00% | $ 72,502 | $ - | $ 10,150 | $ 82,652 | $ 131,056 | $ 48,404 |
| 1970 | Load Management Controls Customer Premises | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1975 | Load Management Controls Utility Premises | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1980 | System Supervisor Equipment | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1985 | Miscellaneous Fixed Assets | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1990 | Other Tangible Property | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1995 | Contributions & Grants | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| A | Maj Rollup Acc Dep Suspense | -$ 240,316 | | -$ 240,316 | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| B | Acc Dep - Contra for Group Retirement | $ 172,061 | | $ 172,061 | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| C | Suspense/Conversion/Error | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| | **Total** | **$ 40,902,038** | **-$ 3,679,791** | **$ 44,581,829** | **$ -** | **$ -** | **$ -** | **$ 3,606,498** | | | | | **$ 2,270,942** | **$ -** | **$ 81,162** | **$ 2,352,104** | **$ 2,876,863** | **$ 524,759** |

**General:** Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial

**Notes:**

1. until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. the prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

## Appendix 2-C
## Depreciation and Amortization Expense
## 2018 (Accounting Standard USGAAP)

**This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B**

| Scenario that applies | Applicable Years and Accounting Standard | Year Reflected in Schedule Below | Accounting Standard Reflected in Schedule Below |
|---|---|---|---|
| Rebasing for the first time with depreciation policy changes made in 2012. | This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Rebasing for the first time with depreciation policy changes made in 2013. ☑ | This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |
| Already rebased with depreciation policy changes in a prior rate application | This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material). | | |

| | | Book Values | | | | | | | Service Lives | | | | Depreciation Expense | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Account | Description | Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1] | Less Fully Depreciated [7] | Net Amount of Existing Assets Before Policy Change to be Depreciated | Opening Gross Book Value of Assets Acquired After Policy Change [2] | Less Fully Depreciated [8] | Net Amount of Assets Acquired After Policy Change to be Depreciated | Current Year Additions | Average Remaining Life of Assets Existing Before Policy Change [3] | Depreciation Rate Assets Acquired After Policy Change | Life of Assets Acquired After Policy Change [4] | Depreciation Rate on New Additions | Depreciation Expense on Assets Existing Before Policy Change | Depreciation Expense on Assets Acquired After Policy Change | Depreciation Expense on Current Year Additions [5] | Total Current Year Depreciation Expense | Depreciation Expense per Appendix 2-BA Fixed Assets, Column J | Variance [6] |
| | | a | b | c = a-b | d | e | f = d- e | g | h | i = 1/h | j | k = 1/j | l = c/j was l = c/h | m = f/j | n = g*0.5/j | o = l+m+n | p | q = p-o |
| 1611 | Computer Software (Formally known as Account 1925) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1612 | Land Rights (Formally known as Account 1906) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1615 | Land | $ - | | $ - | | | $ - | $ - | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1620 | Buildings &Fixtures | $ 3,224,503 | | $ 3,224,503 | | | $ - | $ 17,280 | | 0.00% | 35.00 | 2.86% | $ 92,129 | $ - | $ 247 | $ 92,376 | $ 140,590 | $ 48,214 |
| 1650 | Reservoirs Dams & Water | $ 176,571 | | $ 176,571 | | | $ - | $ - | | 0.00% | - | 0.00% | $ - | $ - | $ - | $ - | $ 29,429 | $ 29,429 |
| 1665 | Fuel Holders Produce | $ 6,952,773 | | $ 6,952,773 | | | $ - | $ 103,680 | | 0.00% | 35.00 | 2.86% | $ 198,651 | $ - | $ 1,481 | $ 200,132 | $ 223,494 | $ 23,362 |
| 1670 | Prime Movers | $ 5,256,510 | -$ 3,093,416 | $ 8,349,926 | | | $ - | $ 972,469 | | 0.00% | 10.00 | 10.00% | $ 834,993 | $ - | $ 48,623 | $ 883,616 | $ 1,143,573 | $ 259,957 |
| 1675 | Generators | $ 4,802,163 | -$ 527,894 | $ 5,330,057 | | | $ - | $ 375,896 | | 0.00% | 16.00 | 6.25% | $ 333,129 | $ - | $ 11,747 | $ 344,875 | $ 443,590 | $ 98,715 |
| 1680 | Accessory Electc Equ | $ 1,645,081 | -$ 35,795 | $ 1,680,876 | | | $ - | $ 545,400 | | 0.00% | 17.00 | 5.88% | $ 98,875 | $ - | $ 16,041 | $ 114,916 | $ 180,788 | $ 65,872 |
| 1685 | Misc Power Plant Equ | $ 2,060,518 | -$ 14,451 | $ 2,074,969 | | | $ - | $ 86,400 | | 0.00% | 25.00 | 4.00% | $ 82,999 | $ - | $ 1,728 | $ 84,727 | $ 135,336 | $ 50,609 |
| 1805 | Land | $ 175,989 | | $ 175,989 | | | $ - | $ - | | 0.00% | 50.00 | 2.00% | $ 3,520 | $ - | $ - | $ 3,520 | $ 5,712 | $ 2,192 |
| 1806 | L&Rights | $ 162,136 | | $ 162,136 | | | $ - | $ - | | 0.00% | 100.00 | 1.00% | $ 1,621 | $ - | $ - | $ 1,621 | $ 2,271 | $ 650 |
| 1808 | Buildings | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1810 | Leasehold Improvements | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1815 | Transformer Station Equipment >50 kV | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1820 | Distribution Station Equipment <50 kV | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1825 | Storage Battery Equipment | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1830 | Poles, Towers & Fixtures | $ 2,877,236 | -$ 181 | $ 2,877,417 | | | $ - | $ 205,620 | | 0.00% | 55.00 | 1.82% | $ 52,317 | $ - | $ 1,869 | $ 54,186 | $ 63,120 | $ 8,934 |
| 1835 | Overhead Conductors & Devices | $ 1,988,214 | -$ 22 | $ 1,988,236 | | | $ - | $ 143,934 | | 0.00% | 50.00 | 2.00% | $ 39,765 | $ - | $ 1,439 | $ 41,204 | $ 49,044 | $ 7,840 |
| 1840 | Underground Conduit | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1845 | Underground Conductors & Devices | $ 139,909 | -$ 159 | $ 140,068 | | | $ - | $ - | | 0.00% | 30.00 | 3.33% | $ 4,669 | $ - | $ - | $ 4,669 | $ 7,701 | $ 3,032 |
| 1850 | Line Transformers | $ 1,670,652 | -$ 25 | $ 1,670,677 | | | $ - | $ 112,726 | | 0.00% | 35.00 | 2.86% | $ 47,734 | $ - | $ 1,610 | $ 49,344 | $ 58,888 | $ 9,544 |
| 1855 | Services (Overhead & Underground) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1860 | Meters | $ 406,541 | -$ 63 | $ 406,604 | | | $ - | $ 51,040 | | 0.00% | 5.00 | 20.00% | $ 81,321 | $ - | $ 5,104 | $ 86,425 | $ 47,046 | -$ 39,379 |
| 1860 | Meters (Smart Meters) | | | $ - | | | $ - | | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1905 | Land | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1908 | Buildings & Fixtures | $ 9,606,023 | | $ 9,606,023 | | | $ - | $ 407,100 | | 0.00% | 40.00 | 2.50% | $ 240,151 | $ - | $ 5,089 | $ 245,239 | $ 237,386 | -$ 7,853 |
| 1910 | Leasehold Improvements | $ 47,850 | | $ 47,850 | | | $ - | $ - | | 0.00% | 10.00 | 10.00% | $ 4,785 | $ - | $ - | $ 4,785 | $ 12,993 | $ 8,208 |
| 1915-A | Office Furniture & Equipment (10 years) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1915 | Office Furniture & Equipment (5 & 7 years) | $ 34,795 | | $ 34,795 | | | $ - | $ 17,500 | | 0.00% | 7.00 | 14.29% | $ 4,971 | $ - | $ 1,250 | $ 6,221 | $ 7,646 | $ 1,425 |
| 1920-A | Computer Equipment - Hardware | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1920-B | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ 8,750 | | $ 8,750 | | | $ - | $ 8,750 | | 0.00% | 5.00 | 20.00% | $ 1,750 | $ - | $ 875 | $ 2,625 | $ - | -$ 2,625 |
| 1930 | Transportation Equipment | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1935 | Stores Equipment | $ 55,896 | | $ 55,896 | | | $ - | $ 26,250 | | 0.00% | 8.00 | 12.50% | $ 6,987 | $ - | $ 1,641 | $ 8,628 | $ 16,838 | $ 8,210 |
| 1940 | Tools, Shop & Garage Equipment | $ 47,713 | | $ 47,713 | | | $ - | $ - | | 0.00% | 6.00 | 16.67% | $ 7,952 | $ - | $ - | $ 7,952 | $ 14,625 | $ 6,673 |
| 1945 | Measurement & Testing Equipment | $ 35,915 | | $ 35,915 | | | $ - | $ 21,000 | | 0.00% | 5.00 | 20.00% | $ 7,183 | $ - | $ 2,100 | $ 9,283 | $ 14,917 | $ 5,634 |
| 1950 | Power Operated Equipment | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1955 | Communications Equipment | -$ 9,162 | -$ 7,788 | -$ 1,374 | | | $ - | $ - | | 0.00% | 7.00 | 14.29% | -$ 196 | $ - | $ - | -$ 196 | $ 687 | $ 883 |
| 1955 | Communication Equipment (Smart Meters) | | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | | $ - |
| 1960 | Miscellaneous Equipment | $ 332,952 | | $ 332,952 | | | $ - | $ 101,500 | | 0.00% | 5.00 | 20.00% | $ 66,590 | $ - | $ 10,150 | $ 76,740 | $ 105,872 | $ 29,132 |
| 1970 | Load Management Controls Customer Premises | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1975 | Load Management Controls Utility Premises | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1980 | System Supervisor Equipment | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1985 | Miscellaneous Fixed Assets | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1990 | Other Tangible Property | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| 1995 | Contributions & Grants | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| A | Maj Rollup Acc Dep Suspense | -$ 240,316 | | -$ 240,316 | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| B | Acc Dep - Contra for Group Retirement | $ 172,061 | | $ 172,061 | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| C | Suspense/Conversion/Error | $ - | | $ - | | | $ - | $ - | | 0.00% | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - |
| | **Total** | **$ 41,631,273** | **-$ 3,679,791** | **$ 45,311,064** | **$ -** | **$ -** | **$ -** | **$ 3,196,545** | | | | | **$ 2,211,893** | **$ -** | **$ 110,995** | **$ 2,322,887** | **$ 2,941,546** | **$ 618,659** |

**General:** Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial

**Notes:**

1. until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. the prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

# COST OF CAPITAL

## 1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of financing of Remotes' capital requirements for the 2018 test year.

## 2.0 CAPITAL STRUCTURE

Consistent with the Board's Decision in RP-1998-0001 and subsequent Decisions, Remotes is 100% debt-financed and is operated as a break-even company. Remotes does not plan to seek a return on equity. As such, Remotes' cost of capital is based on 100% debt, consisting of 4% deemed short term debt and 96% long term debt.

Long term debt includes $43,000K of long term debt issued to Hydro One Inc., reflecting debt issued by Hydro One Inc. to third party public debt investors, and ($333)K of deemed long term debt.

## 3.0 DEEMED SHORT-TERM DEBT

The Board has determined that the deemed amount of short-term debt that should be factored into rate setting be fixed at 4% of rate base and that the deemed short-term debt rate be based on the forecast three-month bankers' acceptance rate plus the average spread as determined through a Board staff survey of real market quotes from major banks[1]. For Remotes, the deemed short-term rate is 1.76%, consistent with the Deemed Short-Term Debt Rate in the OEB's Cost of Capital Parameter Updates for 2017 Cost of Service Applications for Rates Effective January 1, 2017, dated October 27, 2016. Remotes assumes that the deemed short term debt rate for 2018 will be updated in accordance with the Board's December 11, 2009, Cost of Capital Report upon the final decision in this case.

## 4.0 THIRD PARTY LONG-TERM DEBT

The long-term debt rate is calculated as the weighted average cost rate on embedded debt, and new debt (debt issued after the last OEB-approved rate application). The weighted average rate on long-term debt is 4.63% for 2018. Details of Remotes long-term debt rate calculation for the 2018 test year are shown in Exhibit E2, Tab 2, Schedule 1, Attachment 6.

### 4.1 Embedded Debt

The Board has determined in its Cost of Capital Report that for embedded debt, the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt. Remotes' embedded long-term debt was issued in 2005 has a maturity date of May 20, 2036, an interest coupon rate of 5.36% per annum and an effective cost rate of 5.60%. It is shown at Exhibit C2, Tab 8, Schedule 2, page 1. The effective cost rate on this embedded debt was approved by the Board as part of EB-2008-0232.

[1] The Board indicated in Appendix D of the December 11, 2009 Cost of Capital Report that, once a year, Board staff will obtain real market quotes from major banks, for issuing spreads over Bankers Acceptance rates to calculate an average spread.

### 4.2 New Debt

The Board has determined in its Cost of Capital Report that the rate for new debt that is held by a third-party public debt investor will be the prudently negotiated contract rate. This would include recognition of premiums and discounts.

In June 2014, Hydro One Inc. issued $350 million of thirty-year notes, of which $10 million was mapped to Remotes. The new debt has a maturity date of June 6, 2044, an interest coupon rate of 4.17% per annum and an effective cost rate of 4.21%, including issuance costs such as issue discount and agency commissions.

In February 2016, Hydro One Inc. issued $500 million of ten-year notes, of which $10 million was mapped to Remotes. The new debt has a maturity date of February 24, 2026, an interest coupon rate of 2.77% per annum and an effective cost rate of 2.82%, including issuance costs such as issue discount and agency commissions.

## 5.0 DEEMED LONG-TERM DEBT

Deemed long-term debt of ($333)K in 2018 reflects the remaining amount of debt required to balance the total financing with the rate base. In its Decision in EB-2008-0232, the Board indicated that, “For companies with embedded debt, it is the cost of this embedded debt which should be applied to any additional notional (or deemed) debt that is required to balance the capital structure.” Accordingly, the deemed long-term debt is calculated at 4.63%.

## 6.0 COST OF CAPITAL SUMMARY

Remotes' 2018 rate base is $44,445K which results in a weighted cost on rate base of 4.52%, as shown in table below.

**2018 Cost of Capital**

| Particulars | (in $K) | % Of Rate Base | Cost Rate (%) | Weighted Cost Rate % | Cost of Capital (in $K) |
|---|---|---|---|---|---|
| Deemed short-term debt | 1,788 | 4.0% | 1.76% | 0.07% | 31 |
| Third Party long-term debt | 43,000 | 96.7% | 4.63% | 4.48% | 1,991 |
| Deemed long-term debt | (333) | -0.7% | 4.63% | -0.03% | (15) |
| **Total** | **44,445** | **100%** | | **4.52%** | **$2,007** |

The historical debt summary schedules have been provided at Exhibit E2, Tab 2, Schedule 1, Attachments 1 to 4. The capital structure and cost of capital for the Board Approved Year 2013 and the Test Year 2018 have been provided at Exhibit E2, Tab 1, Schedules 1 and 2.

# Appendix 2-OA
# Capital Structure and Cost of Capital

**This table must be completed for the last Board-approved year and the test year.**

**Year:** 2013 Board Approved

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | (%) | | ($) | (%) | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 96.00% | | $39,446 | 5.60% | $2,209 |
| 2 | Short-term Debt | 4.00% | (1) | $1,644 | 2.01% | $33 |
| 3 | **Total Debt** | 100.0% | | $41,090 | 5.46% | $2,242 |
| | **Equity** | | | | | |
| 4 | Common Equity | | | $ - | | $ - |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 0.0% | | $ - | 0.00% | $ - |
| 7 | **Total** | 100.0% | | $41,090 | 5.46% | $2,242 |

**Notes**

**(1)** 4.0% unless an applicant has proposed or been approved for a different amount.

# Appendix 2-OA
# Capital Structure and Cost of Capital

**This table must be completed for the last Board-approved year and the test year.**

**Year:** 2018 Test Year

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | (%) | | ($) | (%) | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 96.00% | | $42,667 | 4.63% | $1,975 |
| 2 | Short-term Debt | 4.00% | (1) | $1,778 | 1.76% | $31 |
| 3 | **Total Debt** | 100.0% | | $44,445 | 4.52% | $2,007 |
| | **Equity** | | | | | |
| 4 | Common Equity | | | $ - | | $ - |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 0.0% | | $ - | 0.00% | $ - |
| 7 | **Total** | 100.0% | | $44,445 | 4.52% | $2,007 |

**Notes**

**(1)** 4.0% unless an applicant has proposed or been approved for a different amount.

# REMOTES DEBT INSTRUMENTS 2013 TO 2018

The following attachments contain the OEB Chapter 2, Appendices 2-OB, Debt Instruments for the years 2013 to 2018 inclusive.

Attachment 1: Hydro One Remote Communities Inc. Debt Instruments 2013
Attachment 2: Hydro One Remote Communities Inc. Debt Instruments 2014
Attachment 3: Hydro One Remote Communities Inc. Debt Instruments 2015
Attachment 4: Hydro One Remote Communities Inc. Debt Instruments 2016
Attachment 5: Hydro One Remote Communities Inc. Debt Instruments 2017
Attachment 6: Hydro One Remote Communities Inc. Debt Instruments 2018

# Appendix 2-OB
# Debt Instruments

**This table must be completed for all required historical years, the bridge year and the test year.**

**Year** 2013

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Average Principal ($) | Effective Rate (%) [2] | Interest ($) [1] | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | $23M note maturing May 20, 2036 | Hydro One Inc. | Third-Party | Fixed Rate | 19-May-05 | 31 | $ 23,000,000 | 5.60% | $ 1,288,000 | |
| 2 | | | | | | | | | $ - | |
| 3 | | | | | | | | | $ - | |
| 4 | | | | | | | | | $ - | |
| 5 | | | | | | | | | $ - | |
| 6 | | | | | | | | | $ - | |
| 7 | | | | | | | | | $ - | |
| 8 | | | | | | | | | $ - | |
| 9 | | | | | | | | | $ - | |
| 10 | | | | | | | | | $ - | |
| 11 | | | | | | | | | $ - | |
| 12 | | | | | | | | | $ - | |
| | | | | | | | | | | |
| Total | | | | | | | $ 23,000,000 | 5.60% | $ 1,288,000 | |

**Notes**

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any subsequent update issued by the Board.

3 Add more lines above row 12 if necessary.

## Appendix 2-OB
## Debt Instruments

**This table must be completed for all required historical years, the bridge year and the test year.**

**Year** 2014

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Average Principal ($) | Effective Rate (%) [2] | Interest ($) [1] | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | $23M note maturing May 20, 2036 | Hydro One Inc. | Third-Party | Fixed Rate | 19-May-05 | 31 | $ 23,000,000 | 5.60% | $ 1,288,000 | |
| 2 | $10M note maturing June 6, 2044 | Hydro One Inc. | Third-Party | Fixed Rate | 6-Jun-14 | 30 | $ 5,698,630 | 4.21% | $ 239,912 | Average principal represents the pro-rated amount outstanding in 2014 |
| 3 | | | | | | | | | $ - | |
| 4 | | | | | | | | | $ - | |
| 5 | | | | | | | | | $ - | |
| 6 | | | | | | | | | $ - | |
| 7 | | | | | | | | | $ - | |
| 8 | | | | | | | | | $ - | |
| 9 | | | | | | | | | $ - | |
| 10 | | | | | | | | | $ - | |
| 11 | | | | | | | | | $ - | |
| 12 | | | | | | | | | $ - | |
| | | | | | | | | | | |
| Total | | | | | | | $ 28,698,630 | 5.32% | $ 1,527,912 | |

**Notes**

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any subsequent update issued by the Board.
3 Add more lines above row 12 if necessary.

# Appendix 2-OB
# Debt Instruments

**This table must be completed for all required historical years, the bridge year and the test year.**

**Year** 2015

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Average Principal ($) | Effective Rate (%) [2] | Interest ($) [1] | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | $23M note maturing May 20, 2036 | Hydro One Inc. | Third-Party | Fixed Rate | 19-May-05 | 31 | $ 23,000,000 | 5.60% | $ 1,288,000 | |
| 2 | $10M note maturing June 6, 2044 | Hydro One Inc. | Third-Party | Fixed Rate | 6-Jun-14 | 30 | $ 10,000,000 | 4.21% | $ 421,000 | |
| 3 | | | | | | | | | $ - | |
| 4 | | | | | | | | | $ - | |
| 5 | | | | | | | | | $ - | |
| 6 | | | | | | | | | $ - | |
| 7 | | | | | | | | | $ - | |
| 8 | | | | | | | | | $ - | |
| 9 | | | | | | | | | $ - | |
| 10 | | | | | | | | | $ - | |
| 11 | | | | | | | | | $ - | |
| 12 | | | | | | | | | $ - | |
| | | | | | | | | | | |
| Total | | | | | | | $ 33,000,000 | 5.18% | $ 1,709,000 | |

**Notes**

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any subsequent update issued by the Board.

3 Add more lines above row 12 if necessary.

## Appendix 2-OB
## Debt Instruments

**This table must be completed for all required historical years, the bridge year and the test year.**

**Year** 2016

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Average Principal ($) | Effective Rate (%) [2] | Interest ($) [1] | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | $23M note maturing May 20, 2036 | Hydro One Inc. | Third-Party | Fixed Rate | 19-May-05 | 31 | $ 23,000,000 | 5.60% | $ 1,288,000 | |
| 2 | $10M note maturing June 6, 2044 | Hydro One Inc. | Third-Party | Fixed Rate | 6-Jun-14 | 30 | $ 10,000,000 | 4.21% | $ 421,000 | |
| 3 | $10M note maturing Feb 24, 2026 | Hydro One Inc. | Third-Party | Fixed Rate | 24-Feb-16 | 10 | $ 8,497,268 | 2.82% | $ 239,623 | Average principal represents the pro-rated amount outstanding in 2016 |
| 4 | | | | | | | | | $ - | |
| 5 | | | | | | | | | $ - | |
| 6 | | | | | | | | | $ - | |
| 7 | | | | | | | | | $ - | |
| 8 | | | | | | | | | $ - | |
| 9 | | | | | | | | | $ - | |
| 10 | | | | | | | | | $ - | |
| 11 | | | | | | | | | $ - | |
| 12 | | | | | | | | | $ - | |
| | | | | | | | | | | |
| Total | | | | | | | $ 41,497,268 | 4.70% | $ 1,948,623 | |

**Notes**

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any subsequent update issued by the Board.

3 Add more lines above row 12 if necessary.

# Appendix 2-OB
# Debt Instruments

**This table must be completed for all required historical years, the bridge year and the test year.**

**Year** 2017

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Average Principal ($) | Effective Rate (%) [2] | Interest ($) [1] | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | $23M note maturing May 20, 2036 | Hydro One Inc. | Third-Party | Fixed Rate | 19-May-05 | 31 | $ 23,000,000 | 5.60% | $ 1,288,000 | |
| 2 | $10M note maturing June 6, 2044 | Hydro One Inc. | Third-Party | Fixed Rate | 6-Jun-14 | 30 | $ 10,000,000 | 4.21% | $ 421,000 | |
| 3 | $10M note maturing Feb 24, 2026 | Hydro One Inc. | Third-Party | Fixed Rate | 24-Feb-16 | 10 | $ 10,000,000 | 2.82% | $ 282,000 | |
| 4 | | | | | | | | | $ - | |
| 5 | | | | | | | | | $ - | |
| 6 | | | | | | | | | $ - | |
| 7 | | | | | | | | | $ - | |
| 8 | | | | | | | | | $ - | |
| 9 | | | | | | | | | $ - | |
| 10 | | | | | | | | | $ - | |
| 11 | | | | | | | | | $ - | |
| 12 | | | | | | | | | $ - | |
| | | | | | | | | | | |
| Total | | | | | | | $ 43,000,000 | 4.63% | $ 1,991,000 | |

**Notes**

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any
3 Add more lines above row 12 if necessary.

# Appendix 2-OB
# Debt Instruments

**This table must be completed for all required historical years, the bridge year and the test year.**

**Year** 2018

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Average Principal ($) | Effective Rate (%) [2] | Interest ($) [1] | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | $23M note maturing May 20, 2036 | Hydro One Inc. | Third-Party | Fixed Rate | 19-May-05 | 31 | $ 23,000,000 | 5.60% | $ 1,288,000 | |
| 2 | $10M note maturing June 6, 2044 | Hydro One Inc. | Third-Party | Fixed Rate | 6-Jun-14 | 30 | $ 10,000,000 | 4.21% | $ 421,000 | |
| 3 | $10M note maturing Feb 24, 2026 | Hydro One Inc. | Third-Party | Fixed Rate | 24-Feb-16 | 10 | $ 10,000,000 | 2.82% | $ 282,000 | |
| 4 | | | | | | | | | $ - | |
| 5 | | | | | | | | | $ - | |
| 6 | | | | | | | | | $ - | |
| 7 | | | | | | | | | $ - | |
| 8 | | | | | | | | | $ - | |
| 9 | | | | | | | | | $ - | |
| 10 | | | | | | | | | $ - | |
| 11 | | | | | | | | | $ - | |
| 12 | | | | | | | | | $ - | |
| | | | | | | | | | | |
| Total | | | | | | | $ 43,000,000 | 4.63% | $ 1,991,000 | |

**Notes**

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any
3 Add more lines above row 12 if necessary.

# REVENUE REQUIREMENT

## 1.0 SUMMARY OF REVENUE REQUIREMENT

Remotes follows standard regulatory practice and has calculated revenue requirement consistent with the principles of the 2006 Electricity Distribution Rate Handbook as follows:

**Table 1**

**Revenue Requirement (in $K)**

| | | |
|---|---|---|
| OM&A | $50,143 | Exhibit D1, Tab 1, Schedule1 |
| Depreciation and Amortization | 4,608 | Exhibit D1, Tab 6, Schedule 1 |
| Income Taxes | (69) | Exhibit D2, Tab 8, Schedule 1 |
| Cost of Capital (100% debt) | 2,007 | Exhibit E1, Tab 1, Schedule 1 |
| **Total Revenue Requirement** | **$56,689** | **Exhibit F1, Tab 1, Schedule 1** |
| Annual RRRP | (38,078) | Exhibit F2, Tab 1, Schedule 2 |
| Other Revenues | (999) | Exhibit G1, Tab 3, Schedule 1 |
| **Rate Revenue Requirement** | **$17,612** | **Exhibit F2, Tab 1, Schedule 1** |

The resultant Total Revenue Requirement of $56,689K is the amount required by Remotes to ensure the most appropriate, cost-effective solution to respond to corporate objectives mainly related to public and employee safety and regulatory requirements. The rate revenue requirement of $17,612K represents the amount to be funded through rates by Remotes customers.

## 2.0 CALCULATION OF REVENUE REQUIREMENT

The details of the Revenue Requirement components are as follows:

### 2.1 OM&A Expense

| | (in $K) |
|---|---|
| Generation | $44,159 |
| Distribution | 2,203 |
| Customer Care | 1,999 |
| Community Relations | 305 |
| Shared Services and Other Costs | 1,342 |
| External Costs | 135 |
| **Total OM&A** | **$50,143** |

### 2.2 Depreciation and Amortization Expense

| | |
|---|---|
| Depreciation | $3,576 |
| Amortization | 1,032 |
| **Total Expense** | **$4,608** |

### 2.3 Payments in Lieu of Corporate Income Taxes

| | |
|---|---|
| Income Before Payments in Lieu of Corporate Income Taxes | $(262) |
| Tax Rate | 26.5% |
| **Total Payments in Lieu of Corporate Income Taxes** | **$(69)**[1] |

[1] Calculated on the basis of regulatory taxes payable, as per 2006 Electricity Distribution Rate Handbook; see Exhibit D2, Tab 8, Schedule 2 for detailed calculation.

### 2.4 Cost of Capital

Cost of Capital (100% debt) $2,007

## 3.0 REVENUE REQUIREMENT – COMPARISON OF YEAR 2013 TO YEAR 2018

Table 2 below compares, by element, the Year 2013 Board approved Revenue Requirement (as per EB-2012-0137) against the Year 2018 proposed Revenue Requirement.

**Table 2**

**Comparison of Revenue Requirements: 2013 vs. 2018 (in $K)**

| Line No | Description | Year 2013 OEB-Approved | Year 2018 Test | Difference |
|---|---|---|---|---|
| 1 | OM&A | $43,483 | $50,143 | $6,660 |
| 2 | Depreciation / Amortization | 5,178 | 4,608 | (570) |
| 3 | Income Taxes | (187) | (69) | 118 |
| 4 | Cost of Capital | 1,631 | 2,007 | 376 |
| 5 | **Total Revenue Requirement** | **$50,105** | **$56,689** | **$6,584** |
| 6 | Annual RRRP | (32,259) | (38,078) | (5,819) |
| 7 | Other Revenues | (586) | (999) | (413) |
| 8 | Rate Revenue Requirement | **$17,260** | **$17,612** | **$352** |
| 9 | *% Change (Test vs. 2013 Board Approved)* | | | *2.0%* |

The higher Rate Revenue Requirement for 2018 as compared to 2013 reflects the proposed 1.80% increase, Incentive Regulatory Mechanism (IRM) increases of approximately 1.8% in each of the past four years, and increased load growth in the communities, partially offset by the previously expected consumption in the communities of Cat Lake and Pikangikum.

**HYDRO ONE REMOTE COMMUNITIES INC.**
**Calculation of Revenue Requirement**
Year Ending December 31, 2018
(in $K)

| Line No. | Particulars | | 2018 Test Year |
|---|---|---|---|
| | Cost of Service | | |
| 1 | Operating, maintenance & administrative | $ | 50,143 |
| 2 | Depreciation & amortization | | 4,608 |
| 3 | Income taxes | | (69) |
| 4 | Cost of service excluding cost of capital (Note 1) | $ | 54,682 |
| 5 | Cost of capital | | 2,007 |
| 6 | Service revenue requirement | $ | 56,689 |
| 7 | Less Annual RRRP | | (38,078) |
| 8 | Less Other Revenues | | (999) |
| 9 | Total Rate Revenue Requirement | | $ 17,612 |

Note 1: Per Exhibit D2, Tab1, Schedule 1

**HYDRO ONE REMOTE COMMUNITIES INC.**
**Revenue Requirement Work Form**
Calculation of Revenue Requirement and Remote Rate Protection
Year Ending December 31, 2018
(in $K)

| Line No. | Particulars | | 2018 Test Year |
|---|---|---|---|
| | Cost of Service | | |
| 1 | Operating, Maintenance & Administrative | | $ 50,143 |
| | Generation Maintenance | 11,640 | |
| | Generation Operations | 4,919 | |
| | Fuel | 27,600 | |
| | Distribution | 2,203 | |
| | Customer Care | 1,999 | |
| | Community Relations | 305 | |
| | Shared Services & Other Administration Costs | 1,342 | |
| | External Costs | 135 | |
| 2 | Depreciation & amortization | | 4,608 |
| | Depreciation | 3,576 | |
| | Amortization | 1,032 | |
| 3 | Income taxes | (69) | (69) |
| 4 | Cost of service excluding return | | 54,682 |
| 5 | Return on capital | 2,007 | 2,007 |
| 6 | Service revenue requirement | | 56,689 |
| 7 | Less Customer Revenues | | (17,612) |
| | Less Other Revenues | | (999) |
| 8 | **Total Remote Rate Protection Requirement** | | **$ 38,078** |

# LOAD FORECAST AND METHODOLOGY

## 1.0 INTRODUCTION

Remotes' load forecast underpins its revenues from customers and its fuel forecast. Remotes has two broad categories of customers, Standard A or government customers whose rates have historically been set above cost, and those Residential and General Service customers who benefit from Rural and Remote Rate Protection. These two categories are set out in O. Reg. 442/01, the regulation under the *Ontario Energy Board Act, 1998,* that establishes the rules for Rural and Remote Rate Protection ("RRRP"). Most of Remotes' customers pay rates that are subsidized by RRRP and are set well below the per kWh cost to serve from diesel fuel.

Remotes does not have any load transfer agreements with other utilities and, due to its isolation, was not affected by the Load Transfer Policy issued by the Board on March 20, 2016.

## 2.0 LOAD FORECAST

Remotes tracks detailed monthly data on customer numbers and kWh usage by community and by class. This historical data provides the baseline for forecasting revenue usage / kWh sold. Adjustments are made to this baseline data for future years based on average historical growth in usage and historical annual customer changes.

Historical trends include the impact of Remotes' Conservation and Demand Management ("CDM") program and other conservation efforts undertaken directly by the communities through funding from the federal government and the IESO. Forecast program results are not included in the forecast. CDM program results have varied considerably since the program's inception based on the participation of local customers and the willingness of Band Councils to participate in conservation efforts.

Three additional sources of information are also used in compiling this forecast: Band Councils, INAC and employees. Each year, Remotes solicits information from Band Councils on planned construction projects. Remotes also holds an annual planning meeting with INAC for information on program activities that could affect load. Finally, field employees share information about pending connections, in particular when these connections are material, such as the construction of a housing subdivision, school or water treatment plant. Employees are also canvassed for information on communities where generation capacity has reached its limits, forcing a constraint on future near-term peak load growth.

This analysis of forecast load is not checked against external forecasts as these forecasts are not appropriate to use to forecast load in Remotes' service territory. Most of the communities Remotes` serves are northern First Nation reserves, which are not specifically addressed in external reports such as the CMHC Outlook. Furthermore, key market indicators for most external reports such as housing growth do not necessarily apply within remote First Nation reserves. Similarly, an upturn in the overall Canadian or Ontario economy has not historically resulted in a similar increase in economic activity within these communities. In the case of the link between population growth and increases in housing units, for example, increases in population within the communities do not tie directly to an increase in the number of houses. A February 2011 audit report that evaluated INAC`s on-reserve housing support found, for example, that ``while housing stock has increased steadily since 1996 through construction of new units and repairs to damaged units, the results have not kept pace with housing needs. ``[1] Moreover, that same report found that even the rate of new housing construction on reserves does not directly correlate to an increased number of housing units because "the housing build on reserve is not lasting as long as it should and needs replacing sooner than can be afforded." Similarly, the Canadian Senate, through the Standing Committee on Aboriginal Peoples, undertook an assessment of housing in First Nation communities in 2015 and heard that "funding is insufficient to properly maintain a community's housing stock."[2]

Remotes does not normalize its load forecast for weather for three reasons: its communities are very small and are scattered within a wide territory; reliable historical weather station data is not available for any communities within Remotes' service territory (the closest reliable data is for Thunder Bay); and because Remotes is operated as a break-even business, it does not stand to profit as a result of forecasting errors.

Once the load forecast is completed, revenues are calculated based on the rate class usage characteristics and the applicable rate schedules.

Tables 1 and 2 below show the 2018 load forecast by category and customer class.

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[1] Evaluation of INAC`s On-Reserve Housing Support, February 2011, Chapter 5. Available on AANDC`s website:
http://www.aadnc-aandc.gc.ca/aiarch/arp/aev/pubs/ev/orhs/orhs-eng.asp#exe (this is archived information).
[2] Report of the Senate, On Reserve Housing and Infrastructure: Recommendations for Change. Available on the Senate's website https://sencanada.ca/content/sen/committee/412/appa/rms/12jun15/Report-e.htm

**Table 1**

**2018 Non Standard A Load Forecast by Customer Class**

| Non Standard A | | | | | | |
|---|---|---|---|---|---|---|
| | **Residential** | **Seasonal** | **GS 1 Phase** | **GS 3 Phase** | **Streetlight** | **Total** |
| Effective # of Customers | 2,695 | 147 | 306 | 43 | 8 | **3,199** |
| Average kWh's/Customer | 14,447 | 2,125 | 21,006 | 117,256 | 32,906 | - |
| **Total MWh's** | **38,935** | **312** | **6,428** | **5,042** | **263** | **50,980** |

**Table 2**

**2018 Standard A Load Forecast by Customer Class**

| Standard A | | | | | |
|---|---|---|---|---|---|
| | **Residential Road Rail** | **Residential Air Access** | **GS Road Rail** | **GS Air Access** | **Total** |
| Effective # of Customers | 8 | 135 | 22 | 288 | **453** |
| Average kWh's/Customer | 5,971 | 10,510 | 32,283 | 32,668 | |
| **Total MWh's** | **48** | **1,419** | **710** | **9,408** | **11,585** |

Table 3 shows the Load forecast by Standard A and Non Standard A customer categories.

**Table 3**

**2018 Load Forecast Summary Table**

| Load Forecast Summary | |
|---|---|
| Effective # of Standard A Customers | 453 |
| Total Standard A MWhs | 11,585 |
| Effective # of Non Standard A Customers | 3,199 |
| Total Non Standard A MWhs | 50,980 |
| Total Effective # of Customers | 3,652 |
| **Total MWhs** | **62,565** |

# PROPOSED CUSTOMER RATES

## 1.0 INTRODUCTION

Most of Remotes' customers are eligible for Remote Rate Protection under Section 79 of the *Ontario Energy Board Act, 1998*. Under this Act, O. Reg. 442/01 requires the Board to calculate the amount of Rate Protection for these customers. In view of this legislative requirement that sets out rules for setting rates, Remotes did not undertake a cost allocation study as required by Board in the minimum filing requirements (EB-2006-0170) prior to filing this application. A cost allocation study would not have provided any benefit, as customers cannot be charged the cost of supplying power to them without changes to the legislation. Remotes is also not planning to apply the Board's policy to move to fixed distribution rates for its customers because rates for Remotes' customers include the costs of generation and distribution.

Consistent with Remotes' proposal in EB-2008-0232 and EB-2012-0137, which were accepted by the Board, Remotes is proposing to increase rates to customers in its service territory by the average increase in 2017 base distribution rates for all grid-connected residential and general service <50 kW customers in Ontario. OEB staff calculated the average increase following the approach approved in the Board's Decision with Reasons for EB-2008-0232. That Decision prescribed the methodology for calculating average rate increases for other Local Distribution Companies ("LDC") to apply in a cost-of-service proceeding. The calculations and information used by Board Staff are included as Exhibit G1, Tab 2, Schedule 1, Attachment 1.

Because Remotes' rates include both generation and distribution services, Remotes has applied the OEB-prescribed methodology to the total bill in order to capture changes to both generation and distribution costs. This is consistent with the approach taken in EB-2008-0232 and EB-2012-0137.

The average total bill increase calculated by Board staff for 2016-2017 is 1.80%.

The current and proposed rates for each customer class are shown in Table 1.

**Table 1**

**Current and Proposed Remote Community Rates**

| **Year-Round Residential (R2)** | | | |
|---|---|---|---|
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **Service Charge** | $19.45 | $19.80 | 1.8% |
| **Block 1**<br>*First 1,000 kWh* | $0.0915 | $0.0931 | 1.8% |
| **Block 2**<br>*Next 1,500 kWh* | $0.1221 | $0.1243 | 1.8% |
| **Block 3**<br>*All additional (Over 2,500 kWh)* | $0.1840 | $0.1873 | 1.8% |
| | | | |
| **Residential Seasonal (R4)** | | | |
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **Service Charge** | $32.87 | $33.46 | 1.8% |
| **Block 1**<br>*First 1,000 kWh* | $0.0915 | $0.0931 | 1.8% |
| **Block 2**<br>*Next 1,500 kWh* | $0.1221 | $0.1243 | 1.8% |
| **Block 3**<br>*All additional (over 2,500 kWh)* | $0.1840 | $0.1873 | 1.8% |

| General Service Single Phase (G1) | | | |
|---|---|---|---|
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **Service Charge** | $33.06 | $33.66 | 1.8% |
| **Block 1** *First 6,000 kWh* | $0.1026 | $0.1044 | 1.8% |
| **Block 2** *Next 7,000 kWh* | $0.1361 | $0.1385 | 1.8% |
| **Block 3** *All additional (over 13,000 kWh)* | $0.1840 | $0.1873 | 1.8% |
| | | | |
| **General Service Three Phase (G3)** | | | |
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **Service Charge** | $41.39 | $42.14 | 1.8% |
| **Block 1** *First 25,000 kWh* | $0.1026 | $0.1044 | 1.8% |
| **Block 2** *Next 15,000 kWh* | $0.1361 | $0.1385 | 1.8% |
| **Block 3** *All Additional (Over 40,000 kWh)* | $0.1840 | $0.1873 | 1.8% |
| | | | |
| **Street Lighting** | | | |
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **kWh** | $0.1017 | $0.1035 | 1.8% |
| | | | |
| **Standard A Residential Road Rail** | | | |
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **Service Charge** | $0.00 | $0.00 | 0% |
| **Block 1** *First 250 kWh* | $0.6025 | $0.6133 | 1.8% |
| **Block 2** | $0.6884 | $0.7008 | 1.8% |
| **Standard A Residential Air Access** | | | |
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **Service Charge** | $0.00 | $0.00 | 0% |
| **Block 1** *First 250 kWh* | $0.9096 | $0.9260 | 1.8% |
| **Block 2** | $0.9955 | $1.0134 | 1.8% |

| **Standard A General Service Road Rail** | | | |
|---|---|---|---|
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **Service Charge** | 0.00 | 0.00 | 0% |
| **kWh** | $0.6884 | $0.7008 | 1.8% |
| | | | |
| **Standard A General Service Air Access** | | | |
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **Service Charge** | 0.00 | 0.00 | 0% |
| **kWh** | $0.9955 | $1.0134 | 1.8% |
| | | | |
| **Standard A Grid Connected** | | | |
| | **Existing Rates** | **Proposed 2018** | **Increase** |
| **Service Charge** | 0.00 | 0.00 | 0% |
| **kWh** | $0.3119 | $0.3175 | 1.8% |

| Applicant Name | Class | MFC 2017 | VC 2017 | MFC 2016 | VC 2016 | TB 2017 | TB 2016 | $ Chg | % Chg | Average % Chg |
|---|---|---|---|---|---|---|---|---|---|---|
| Algoma Power Inc. | Residential | 32.58 | 18.83 | 27.76 | 21.60 | 51.41 | 49.36 | 2.05 | 4.14% | |
| Algoma Power Inc. | GS < 50 | 24.46 | 68.80 | 23.76 | 66.80 | 93.26 | 90.56 | 2.70 | 2.98% | 3.56% |
| Atikokan Hydro Inc. | Residential | 42.31 | 6.00 | 36.95 | 8.32 | 48.31 | 45.27 | 3.04 | 6.72% | |
| Atikokan Hydro Inc. | GS < 50 | 76.23 | 9.40 | 76.23 | 19.20 | 85.63 | 95.43 | -9.80 | -10.27% | -1.78% |
| Bluewater Power Distribution Corporation | Residential | 23.94 | 9.04 | 19.87 | 13.28 | 32.98 | 33.15 | -0.17 | -0.51% | |
| Bluewater Power Distribution Corporation | GS < 50 | 28.25 | 39.40 | 27.81 | 38.80 | 67.65 | 66.61 | 1.04 | 1.56% | 0.52% |
| Energy Plus Inc. - Brant County | Residential | 19.95 | 8.40 | 15.59 | 12.64 | 28.35 | 28.23 | 0.12 | 0.43% | |
| Energy Plus Inc. - Brant County | GS < 50 | 17.36 | 36.00 | 17.36 | 36.00 | 53.36 | 53.36 | 0.00 | 0.00% | 0.21% |
| Brantford Power Inc. | Residential | 17.80 | 6.08 | 14.64 | 8.80 | 23.88 | 23.44 | 0.44 | 1.88% | |
| Brantford Power Inc. | GS < 50 | 30.14 | 15.80 | 26.46 | 13.80 | 45.94 | 40.26 | 5.68 | 14.11% | 7.99% |
| Burlington Hydro Inc. | Residential | 18.97 | 6.72 | 15.46 | 10.00 | 25.69 | 25.46 | 0.23 | 0.90% | |
| Burlington Hydro Inc. | GS < 50 | 25.95 | 27.80 | 25.54 | 27.40 | 53.75 | 52.94 | 0.81 | 1.53% | 1.21% |
| Energy Plus Inc. - Cambridge and North Dumfries | Residential | 17.97 | 7.36 | 14.52 | 10.96 | 25.33 | 25.48 | -0.15 | -0.59% | |
| Energy Plus Inc. - Cambridge and North Dumfries | GS < 50 | 13.62 | 29.20 | 13.41 | 28.80 | 42.82 | 42.21 | 0.61 | 1.45% | 0.43% |
| Canadian Niagara Power Inc. - Eastern Ontario Power | Residential | 27.72 | 9.76 | 23.44 | 12.16 | 37.48 | 35.60 | 1.88 | 5.28% | |
| Canadian Niagara Power Inc. - Eastern Ontario Power | GS < 50 | 30.02 | 48.80 | 28.26 | 46.00 | 78.82 | 74.26 | 4.56 | 6.14% | 5.71% |
| Canadian Niagara Power Inc. - Fort Erie | Residential | 27.72 | 9.76 | 23.44 | 12.16 | 37.48 | 35.60 | 1.88 | 5.28% | |
| Canadian Niagara Power Inc. - Fort Erie | GS < 50 | 30.02 | 48.80 | 28.26 | 46.00 | 78.82 | 74.26 | 4.56 | 6.14% | 5.71% |
| Canadian Niagara Power Inc. - Port Colborne Hydro Inc. | Residential | 27.72 | 9.76 | 23.44 | 12.16 | 37.48 | 35.60 | 1.88 | 5.28% | |
| Canadian Niagara Power Inc. - Port Colborne Hydro Inc. | GS < 50 | 30.02 | 48.80 | 28.26 | 46.00 | 78.82 | 74.26 | 4.56 | 6.14% | 5.71% |
| Centre Wellington Hydro Ltd. | Residential | 21.02 | 5.93 | 18.30 | 8.80 | 26.95 | 27.10 | -0.15 | -0.54% | |
| Centre Wellington Hydro Ltd. | GS < 50 | 18.44 | 38.40 | 18.15 | 37.80 | 56.84 | 55.95 | 0.89 | 1.59% | 0.53% |
| Chapleau Public Utilities Corporation | Residential | 24.04 | 11.20 | 24.04 | 11.20 | 35.24 | 35.24 | 0.00 | 0.00% | |
| Chapleau Public Utilities Corporation | GS < 50 | 35.18 | 35.80 | 35.18 | 35.80 | 70.98 | 70.98 | 0.00 | 0.00% | 0.00% |
| Entegrus Powerlines Inc. - Chatham-Kent | Residential | 20.99 | 4.16 | 18.98 | 6.16 | 25.15 | 25.14 | 0.01 | 0.04% | |
| Entegrus Powerlines Inc. - Chatham-Kent | GS < 50 | 30.53 | 20.20 | 30.00 | 19.80 | 50.73 | 49.80 | 0.93 | 1.87% | 0.95% |
| COLLUS Power Corporation | Residential | 17.63 | 8.24 | 13.83 | 12.16 | 25.87 | 25.99 | -0.12 | -0.46% | |
| COLLUS Power Corporation | GS < 50 | 21.01 | 27.80 | 20.65 | 27.40 | 48.81 | 48.05 | 0.76 | 1.58% | 0.56% |
| Cooperative Hydro Embrun Inc. | Residential | 21.87 | 5.76 | 18.25 | 8.48 | 27.63 | 26.73 | 0.90 | 3.37% | |
| Cooperative Hydro Embrun Inc. | GS < 50 | 17.90 | 29.60 | 17.57 | 29.00 | 47.50 | 46.57 | 0.93 | 2.00% | 2.68% |
| E.L.K. Energy Inc. | Residential | 13.33 | 4.96 | 13.33 | 4.96 | 18.29 | 18.29 | 0.00 | 0.00% | |
| E.L.K. Energy Inc. | GS < 50 | 15.77 | 10.00 | 15.77 | 10.00 | 25.77 | 25.77 | 0.00 | 0.00% | 0.00% |
| Enersource Hydro Mississauga Inc. | Residential | 19.11 | 5.52 | 15.75 | 8.16 | 24.63 | 23.91 | 0.72 | 3.01% | |
| Enersource Hydro Mississauga Inc. | GS < 50 | 43.60 | 25.40 | 41.47 | 24.20 | 69.00 | 65.67 | 3.33 | 5.07% | 4.04% |
| ENWIN Utilities Ltd. | Residential | 18.78 | 8.48 | 14.88 | 12.56 | 27.26 | 27.44 | -0.18 | -0.66% | |
| ENWIN Utilities Ltd. | GS < 50 | 26.78 | 34.60 | 26.44 | 34.20 | 61.38 | 60.64 | 0.74 | 1.22% | 0.28% |
| Erie Thames Powerlines Corporation | Residential | 23.22 | 7.52 | 19.38 | 11.12 | 30.74 | 30.50 | 0.24 | 0.79% | |
| Erie Thames Powerlines Corporation | GS < 50 | 22.29 | 29.00 | 21.94 | 28.60 | 51.29 | 50.54 | 0.75 | 1.48% | 1.14% |
| Espanola Regional Hydro Distribution Corporation | Residential | 14.07 | 13.60 | 14.07 | 13.60 | 27.67 | 27.67 | 0.00 | 0.00% | |
| Espanola Regional Hydro Distribution Corporation | GS < 50 | 25.22 | 41.40 | 25.22 | 41.40 | 66.62 | 66.62 | 0.00 | 0.00% | 0.00% |
| Essex Powerlines Corporation | Residential | 20.31 | 6.24 | 16.58 | 9.28 | 26.55 | 25.86 | 0.69 | 2.67% | |
| Essex Powerlines Corporation | GS < 50 | 35.13 | 24.00 | 34.53 | 23.60 | 59.13 | 58.13 | 1.00 | 1.72% | 2.19% |
| Festival Hydro Inc. | Residential | 22.20 | 6.72 | 19.21 | 10.00 | 28.92 | 29.21 | -0.29 | -0.99% | |
| Festival Hydro Inc. | GS < 50 | 31.62 | 31.40 | 31.17 | 31.00 | 63.02 | 62.17 | 0.85 | 1.37% | 0.19% |
| Fort Frances Power Corporation | Residential | 26.38 | 5.76 | 22.58 | 8.48 | 32.14 | 31.06 | 1.08 | 3.48% | |
| Fort Frances Power Corporation | GS < 50 | 45.18 | 20.60 | 44.47 | 20.20 | 65.78 | 64.67 | 1.11 | 1.72% | 2.60% |
| Greater Sudbury Hydro Inc. | Residential | 21.41 | 5.04 | 18.63 | 7.44 | 26.45 | 26.07 | 0.38 | 1.46% | |
| Greater Sudbury Hydro Inc. | GS < 50 | 21.99 | 38.00 | 21.64 | 37.40 | 59.99 | 59.04 | 0.95 | 1.61% | 1.53% |
| Grimsby Power Inc. | Residential | 22.45 | 5.36 | 19.55 | 7.92 | 27.81 | 27.47 | 0.34 | 1.24% | |
| Grimsby Power Inc. | GS < 50 | 24.75 | 38.00 | 24.32 | 37.40 | 62.75 | 61.72 | 1.03 | 1.67% | 1.45% |
| Guelph Hydro Electric Systems Inc. | Residential | 22.36 | 7.84 | 18.93 | 11.52 | 30.20 | 30.45 | -0.25 | -0.82% | |

| Applicant Name | Class | MFC 2017 | VC 2017 | MFC 2016 | VC 2016 | TB 2017 | TB 2016 | $ Chg | % Chg | Average % Chg |
|---|---|---|---|---|---|---|---|---|---|---|
| Guelph Hydro Electric Systems Inc. | GS < 50 | 16.59 | 27.80 | 16.33 | 27.40 | 44.39 | 43.73 | 0.66 | 1.51% | 0.34% |
| Haldimand County Hydro Inc. | Residential | 24.47 | 11.92 | 20.74 | 15.84 | 36.39 | 36.58 | -0.19 | -0.52% | |
| Haldimand County Hydro Inc. | GS < 50 | 26.94 | 38.00 | 26.94 | 38.00 | 64.94 | 64.94 | 0.00 | 0.00% | -0.26% |
| Halton Hills Hydro Inc. | Residential | 20.28 | 5.46 | 17.04 | 8.00 | 25.74 | 25.04 | 0.70 | 2.80% | |
| Halton Hills Hydro Inc. | GS < 50 | 28.03 | 20.20 | 27.51 | 19.80 | 48.23 | 47.31 | 0.92 | 1.94% | 2.37% |
| Hearst Power Distribution Company Limited | Residential | 16.01 | 6.80 | 11.93 | 10.08 | 22.81 | 22.01 | 0.80 | 3.63% | |
| Hearst Power Distribution Company Limited | GS < 50 | 18.62 | 12.60 | 18.30 | 12.40 | 31.22 | 30.70 | 0.52 | 1.69% | 2.66% |
| Horizon Utilities Corporation | Residential | 21.34 | 6.48 | 18.80 | 9.68 | 27.82 | 28.48 | -0.66 | -2.32% | |
| Horizon Utilities Corporation | GS < 50 | 41.42 | 21.40 | 41.21 | 21.20 | 62.82 | 62.41 | 0.41 | 0.66% | -0.83% |
| Hydro 2000 Inc. | Residential | 22.10 | 7.28 | 18.31 | 9.60 | 29.38 | 27.91 | 1.47 | 5.27% | |
| Hydro 2000 Inc. | GS < 50 | 22.47 | 19.60 | 22.12 | 19.20 | 42.07 | 41.32 | 0.75 | 1.82% | 3.54% |
| Hydro Hawkesbury Inc. | Residential | 11.90 | 4.08 | 9.60 | 6.08 | 15.98 | 15.68 | 0.30 | 1.91% | |
| Hydro Hawkesbury Inc. | GS < 50 | 15.47 | 12.20 | 15.47 | 12.20 | 27.67 | 27.67 | 0.00 | 0.00% | 0.96% |
| Hydro One Brampton Networks Inc. | Residential | 17.64 | 6.40 | 14.32 | 9.44 | 24.04 | 23.76 | 0.28 | 1.18% | |
| Hydro One Brampton Networks Inc. | GS < 50 | 25.12 | 33.40 | 24.77 | 32.80 | 58.52 | 57.57 | 0.95 | 1.65% | 1.41% |
| Hydro Ottawa Limited | Residential | 16.60 | 12.08 | 12.96 | 15.44 | 28.68 | 28.40 | 0.28 | 0.99% | |
| Hydro Ottawa Limited | GS < 50 | 17.89 | 45.40 | 17.23 | 43.20 | 63.29 | 60.43 | 2.86 | 4.73% | 2.86% |
| Innpower Corporation | Residential | 24.85 | 11.12 | 24.85 | 11.12 | 35.97 | 35.97 | 0.00 | 0.00% | |
| Innpower Corporation | GS < 50 | 34.33 | 16.60 | 34.33 | 16.60 | 50.93 | 50.93 | 0.00 | 0.00% | 0.00% |
| Kenora Hydro Electric Corporation Ltd. | Residential | 25.10 | 5.92 | 22.24 | 8.72 | 31.02 | 30.96 | 0.06 | 0.19% | |
| Kenora Hydro Electric Corporation Ltd. | GS < 50 | 39.22 | 12.40 | 38.72 | 12.20 | 51.62 | 50.92 | 0.70 | 1.37% | 0.78% |
| Kingston Hydro Corporation | Residential | 18.54 | 6.56 | 13.98 | 11.12 | 25.10 | 25.10 | 0.00 | 0.00% | |
| Kingston Hydro Corporation | GS < 50 | 14.59 | 30.20 | 14.27 | 29.20 | 44.79 | 43.47 | 1.32 | 3.04% | 1.52% |
| Kitchener-Wilmot Hydro Inc. | Residential | 16.64 | 6.72 | 13.61 | 10.00 | 23.36 | 23.61 | -0.25 | -1.06% | |
| Kitchener-Wilmot Hydro Inc. | GS < 50 | 27.11 | 26.00 | 26.64 | 25.60 | 53.11 | 52.24 | 0.87 | 1.67% | 0.30% |
| Lakefront Utilities Inc. | Residential | 16.00 | 6.08 | 13.14 | 9.04 | 22.08 | 22.18 | -0.10 | -0.45% | |
| Lakefront Utilities Inc. | GS < 50 | 23.96 | 16.40 | 23.96 | 17.20 | 40.36 | 41.16 | -0.80 | -1.94% | -1.20% |
| Lakeland Power Distribution Ltd. | Residential | 27.15 | 6.08 | 23.66 | 9.04 | 33.23 | 32.70 | 0.53 | 1.62% | |
| Lakeland Power Distribution Ltd. | GS < 50 | 45.32 | 18.40 | 44.61 | 18.20 | 63.72 | 62.81 | 0.91 | 1.45% | 1.53% |
| London Hydro Inc. | Residential | 19.34 | 6.56 | 16.42 | 9.68 | 25.90 | 26.10 | -0.20 | -0.77% | |
| London Hydro Inc. | GS < 50 | 32.25 | 21.60 | 32.25 | 20.80 | 53.85 | 53.05 | 0.80 | 1.51% | 0.37% |
| Entegrus Powerlines Inc. - Strathroy, Mount Brydges & Parkh | Residential | 20.99 | 4.16 | 18.98 | 6.16 | 25.15 | 25.14 | 0.01 | 0.04% | |
| Entegrus Powerlines Inc. - Strathroy, Mount Brydges & Parkh | GS < 50 | 30.53 | 20.20 | 30.00 | 19.80 | 50.73 | 49.80 | 0.93 | 1.87% | 0.95% |
| Entegrus Powerlines Inc. - Dutton | Residential | 20.99 | 4.16 | 18.98 | 6.16 | 25.15 | 25.14 | 0.01 | 0.04% | |
| Entegrus Powerlines Inc. - Dutton | GS < 50 | 30.53 | 20.20 | 30.00 | 19.80 | 50.73 | 49.80 | 0.93 | 1.87% | 0.95% |
| Entegrus Powerlines Inc. - Newbury | Residential | 20.99 | 4.16 | 18.98 | 6.16 | 25.15 | 25.14 | 0.01 | 0.04% | |
| Entegrus Powerlines Inc. - Newbury | GS < 50 | 30.53 | 20.20 | 30.00 | 19.80 | 50.73 | 49.80 | 0.93 | 1.87% | 0.95% |
| Midland Power Utility Corporation | Residential | 23.20 | 8.56 | 19.35 | 12.56 | 31.76 | 31.91 | -0.15 | -0.47% | |
| Midland Power Utility Corporation | GS < 50 | 22.62 | 33.40 | 22.30 | 33.00 | 56.02 | 55.30 | 0.72 | 1.30% | 0.42% |
| Milton Hydro Distribution inc. | Residential | 21.70 | 5.92 | 18.61 | 8.80 | 27.62 | 27.41 | 0.21 | 0.77% | |
| Milton Hydro Distribution inc. | GS < 50 | 16.77 | 35.40 | 16.51 | 34.80 | 52.17 | 51.31 | 0.86 | 1.68% | 1.22% |
| Newmarket - Tay Power Distribution Ltd. - Newmarket | Residential | 21.25 | 6.00 | 18.06 | 8.88 | 27.25 | 26.94 | 0.31 | 1.15% | |
| Newmarket - Tay Power Distribution Ltd. - Newmarket | GS < 50 | 30.55 | 40.00 | 30.16 | 39.40 | 70.55 | 69.56 | 0.99 | 1.42% | 1.29% |

| Applicant Name | Class | MFC 2017 | VC 2017 | MFC 2016 | VC 2016 | TB 2017 | TB 2016 | $ Chg | % Chg | Average % Chg |
|---|---|---|---|---|---|---|---|---|---|---|
| Niagara Peninsula Energy Inc. | Residential | 25.68 | 7.52 | 21.94 | 11.12 | 33.20 | 33.06 | 0.14 | 0.42% | |
| Niagara Peninsula Energy Inc. | GS < 50 | 38.66 | 28.20 | 38.05 | 27.80 | 66.86 | 65.85 | 1.01 | 1.53% | 0.98% |
| Niagara-on-the-Lake Hydro Inc. | Residential | 24.02 | 5.28 | 21.06 | 7.84 | 29.30 | 28.90 | 0.40 | 1.39% | |
| Niagara-on-the-Lake Hydro Inc. | GS < 50 | 39.06 | 23.40 | 38.44 | 23.00 | 62.46 | 61.44 | 1.02 | 1.66% | 1.52% |
| Norfolk Power Distribution Inc. | Residential | 28.81 | 8.72 | 24.85 | 13.12 | 37.53 | 37.97 | -0.44 | -1.16% | |
| Norfolk Power Distribution Inc. | GS < 50 | 49.98 | 31.20 | 49.98 | 31.20 | 81.18 | 81.18 | 0.00 | 0.00% | -0.58% |
| North Bay Hydro Distribution Limited | Residential | 22.17 | 5.84 | 18.90 | 8.64 | 28.01 | 27.54 | 0.47 | 1.71% | |
| North Bay Hydro Distribution Limited | GS < 50 | 24.07 | 37.00 | 23.69 | 36.40 | 61.07 | 60.09 | 0.98 | 1.63% | 1.67% |
| Northern Ontario Wires Inc. | Residential | 30.30 | 7.36 | 24.25 | 9.84 | 37.66 | 34.09 | 3.57 | 10.47% | |
| Northern Ontario Wires Inc. | GS < 50 | 31.76 | 35.40 | 28.27 | 31.60 | 67.16 | 59.87 | 7.29 | 12.18% | 11.32% |
| Oakville Hydro Electricity Distribution Inc. | Residential | 21.95 | 6.56 | 18.22 | 9.68 | 28.51 | 27.90 | 0.61 | 2.19% | |
| Oakville Hydro Electricity Distribution Inc. | GS < 50 | 36.26 | 32.20 | 35.69 | 31.60 | 68.46 | 67.29 | 1.17 | 1.74% | 1.96% |
| Orangeville Hydro Limited | Residential | 21.00 | 5.52 | 18.19 | 8.16 | 26.52 | 26.35 | 0.17 | 0.65% | |
| Orangeville Hydro Limited | GS < 50 | 32.71 | 20.00 | 32.19 | 19.60 | 52.71 | 51.79 | 0.92 | 1.78% | 1.21% |
| Orillia Power Distribution Corporation | Residential | 21.07 | 6.80 | 17.68 | 10.16 | 27.87 | 27.84 | 0.03 | 0.11% | |
| Orillia Power Distribution Corporation | GS < 50 | 37.42 | 33.00 | 37.42 | 33.00 | 70.42 | 70.42 | 0.00 | 0.00% | 0.05% |
| Oshawa PUC Networks Inc. | Residential | 14.22 | 8.72 | 11.21 | 11.36 | 22.94 | 22.57 | 0.37 | 1.64% | |
| Oshawa PUC Networks Inc. | GS < 50 | 16.24 | 32.20 | 16.02 | 31.40 | 48.44 | 47.42 | 1.02 | 2.15% | 1.90% |
| Ottawa River Power Corporation | Residential | 16.47 | 7.92 | 14.02 | 10.32 | 24.39 | 24.34 | 0.05 | 0.21% | |
| Ottawa River Power Corporation | GS < 50 | 22.37 | 25.40 | 22.02 | 25.00 | 47.77 | 47.02 | 0.75 | 1.60% | 0.90% |
| Lakeland Power Distribution Ltd. - Parry Sound Service Territ | Residential | 30.68 | 8.96 | 26.52 | 11.68 | 39.64 | 38.20 | 1.44 | 3.77% | |
| Lakeland Power Distribution Ltd. - Parry Sound Service Territ | GS < 50 | 34.85 | 28.60 | 34.23 | 28.00 | 63.45 | 62.23 | 1.22 | 1.96% | 2.87% |
| Peterborough Distribution Incorporated | Residential | 15.20 | 7.52 | 15.20 | 7.52 | 22.72 | 22.72 | 0.00 | 0.00% | |
| Peterborough Distribution Incorporated | GS < 50 | 31.13 | 17.60 | 31.13 | 17.60 | 48.73 | 48.73 | 0.00 | 0.00% | 0.00% |
| PowerStream Inc. | Residential | 18.51 | 10.40 | 12.90 | 11.44 | 28.91 | 24.34 | 4.57 | 18.78% | |
| PowerStream Inc. | GS < 50 | 28.74 | 36.60 | 26.55 | 28.40 | 65.34 | 54.95 | 10.39 | 18.91% | 18.84% |
| PUC Distribution Inc. | Residential | 16.79 | 8.36 | 13.23 | 10.96 | 25.15 | 24.19 | 0.96 | 3.97% | |
| PUC Distribution Inc. | GS < 50 | 17.11 | 41.00 | 16.87 | 40.40 | 58.11 | 57.27 | 0.84 | 1.47% | 2.72% |
| Renfrew Hydro Inc. | Residential | 17.30 | 9.20 | 13.97 | 11.60 | 26.50 | 25.57 | 0.93 | 3.64% | |
| Renfrew Hydro Inc. | GS < 50 | 31.25 | 30.60 | 31.25 | 30.60 | 61.85 | 61.85 | 0.00 | 0.00% | 1.82% |
| Rideau St. Lawrence Distribution Inc. | Residential | 13.19 | 12.00 | 13.19 | 12.00 | 25.19 | 25.19 | 0.00 | 0.00% | |
| Rideau St. Lawrence Distribution Inc. | GS < 50 | 30.52 | 18.40 | 30.52 | 18.40 | 48.92 | 48.92 | 0.00 | 0.00% | 0.00% |
| Sioux Lookout Hydro Inc. | Residential | 35.56 | 4.80 | 31.23 | 7.12 | 40.36 | 38.35 | 2.01 | 5.23% | |
| Sioux Lookout Hydro Inc. | GS < 50 | 43.55 | 16.40 | 42.86 | 16.20 | 59.95 | 59.06 | 0.89 | 1.51% | 3.37% |
| St. Thomas Energy Inc. | Residential | 20.47 | 6.88 | 17.31 | 10.24 | 27.35 | 27.55 | -0.20 | -0.73% | |
| St. Thomas Energy Inc. | GS < 50 | 24.00 | 32.80 | 23.62 | 32.20 | 56.80 | 55.82 | 0.98 | 1.76% | 0.51% |
| Thunder Bay Hydro Electricity Distribution Inc. | Residential | 15.24 | 7.76 | 15.24 | 7.76 | 23.00 | 23.00 | 0.00 | 0.00% | |
| Thunder Bay Hydro Electricity Distribution Inc. | GS < 51 | 27.14 | 28.00 | 27.14 | 28.00 | 55.14 | 55.14 | 0.00 | 0.00% | 0.00% |
| Tillsonburg Hydro Inc. | Residential | 17.41 | 11.99 | 13.80 | 15.76 | 29.41 | 29.56 | -0.15 | -0.52% | |
| Tillsonburg Hydro Inc. | GS < 52 | 26.36 | 36.80 | 26.02 | 36.40 | 63.16 | 62.42 | 0.74 | 1.19% | 0.33% |
| Toronto Hydro-Electric System Limited | Residential | 27.69 | 12.10 | 22.78 | 15.04 | 39.79 | 37.82 | 1.97 | 5.20% | |
| Toronto Hydro-Electric System Limited | GS < 53 | 32.68 | 60.46 | 30.47 | 56.36 | 93.14 | 86.83 | 6.31 | 7.27% | 6.23% |
| Veridian Connections Inc. | Residential | 19.73 | 6.64 | 16.30 | 9.84 | 26.37 | 26.14 | 0.23 | 0.88% | |
| Veridian Connections Inc. | GS < 54 | 16.90 | 34.00 | 16.63 | 33.40 | 50.90 | 50.03 | 0.87 | 1.74% | 1.31% |
| Wasaga Distribution Inc. | Residential | 17.56 | 6.48 | 14.91 | 9.44 | 24.04 | 24.35 | -0.31 | -1.27% | |
| Wasaga Distribution Inc. | GS < 55 | 15.04 | 30.40 | 14.76 | 29.80 | 45.44 | 44.56 | 0.88 | 1.97% | 0.35% |
| Waterloo North Hydro Inc. | Residential | 23.62 | 8.40 | 19.71 | 12.32 | 32.02 | 32.03 | -0.01 | -0.03% | |
| Waterloo North Hydro Inc. | GS < 56 | 32.47 | 32.40 | 31.96 | 31.80 | 64.87 | 63.76 | 1.11 | 1.74% | 0.85% |
| Welland Hydro-Electric System Corp. | Residential | 22.26 | 5.92 | 18.76 | 8.40 | 28.18 | 27.16 | 1.02 | 3.76% | |
| Welland Hydro-Electric System Corp. | GS < 57 | 30.91 | 18.20 | 29.23 | 17.20 | 49.11 | 46.43 | 2.68 | 5.77% | 4.76% |

| Applicant Name | Class | MFC 2017 | VC 2017 | MFC 2016 | VC 2016 | TB 2017 | TB 2016 | $ Chg | % Chg | Average % Chg |
|---|---|---|---|---|---|---|---|---|---|---|
| Wellington North Power Inc. | Residential | 27.95 | 8.28 | 23.97 | 12.24 | 36.23 | 36.21 | 0.02 | 0.05% | |
| Wellington North Power Inc. | GS < 58 | 42.31 | 36.40 | 41.71 | 35.80 | 78.71 | 77.51 | 1.20 | 1.55% | 0.80% |
| | | | | | | | | | | |
| West Coast Huron Energy Inc. | Residential | 25.65 | 9.28 | 21.60 | 13.84 | 34.93 | 35.44 | -0.51 | -1.44% | |
| West Coast Huron Energy Inc. | GS < 59 | 32.17 | 22.00 | 31.76 | 21.80 | 54.17 | 53.56 | 0.61 | 1.14% | -0.15% |
| | | | | | | | | | | |
| Westario Power Inc. | Residential | 20.06 | 6.56 | 16.31 | 9.68 | 26.62 | 25.99 | 0.63 | 2.42% | |
| Westario Power Inc. | GS < 60 | 25.14 | 22.60 | 24.74 | 22.20 | 47.74 | 46.94 | 0.80 | 1.70% | 2.06% |
| | | | | | | | | | | |
| Whitby Hydro Electric Corporation | Residential | 24.57 | 6.08 | 21.20 | 9.04 | 30.65 | 30.24 | 0.41 | 1.36% | |
| Whitby Hydro Electric Corporation | GS < 61 | 21.39 | 42.00 | 21.05 | 41.40 | 63.39 | 62.45 | 0.94 | 1.51% | 1.43% |
| | | | | | | | | | | |
| Woodstock Hydro Services Inc. | Residential | 19.77 | 10.64 | 16.38 | 14.24 | 30.41 | 30.62 | -0.21 | -0.69% | |
| Woodstock Hydro Services Inc. | GS < 62 | 25.19 | 29.00 | 25.19 | 29.00 | 54.19 | 54.19 | 0.00 | 0.00% | -0.34% |

| | |
|---|---|
| **Average Percent Change** | **1.80%** |

# OTHER REVENUES

## 1.0 OVERVIEW

This Exhibit details revenues that are not derived directly from customer electricity rates. External and Other revenues include revenues based on OEB-approved specific service charges as set out in the Board's 2006 Electricity Distribution Rate Handbook, late payment revenues and revenues where no specific OEB amounts or charges have been set.

In cases where no specific amounts have been set, Remotes costs external work on the basis of cost causality with estimates calculated in the same way as internal work using the standard labor rates (resource rate), equipment rates, material surcharge and overhead rates. See Exhibit D1, Tab 5, Schedule 1 for a description of Costing of Work.

External revenues also include work performed for external parties, including Hydro One Networks, the Electrical Safety Authority, First Nation operated Independent Power Authorities, and work performed on First Nation assets within Remotes' service territory.

Rural or Remote Rate Protection is discussed in Exhibit G1, Tab 4, Schedule 1.

## 2.0 LATE PAYMENT AND SPECIFIC SERVICE CHARGES

When the total amount of a customer's bill has not been paid by the due date, a late payment charge may be applied to the outstanding balance. Remotes applies a late payment charge to customer outstanding balances, nineteen (19) days after the billing date. The charge is 1.5% per month and is compounded monthly, resulting in a charge of 19.56% per annum. This is a standard business practice for overdue accounts. Remotes does not propose to change its current Late Payment Charge, as this charge complies with all legislative and regulatory requirements. When Remotes performs work such as work performed working on the Weagamow First-Nation owned generator for customers and the invoice for the work is not paid by the due date, the same late payment interest charges are applied.

Remotes also charges for other specific services that it performs as part of its utility business. Remotes does not propose to change the rates for these charges, as they are consistent with charges levied by other Ontario electricity distributors. Table 1, below shows Remotes' charges for specific services and late payment fees.

**Table 1**

**Late Payment and Specific Service Charges ($000s)**

| **Service Description** | **Charge** |
|---|---|
| Late Payment Charge - per month | 1.5% |
| Late Payment Charge - per anum | 19.56% |
| Dispute Meter Test (if meter found correct) | $30.00 |
| Collection/Disconnection/Load Limiter/Reconnection (if in community) | $65.00 |
| Account Set-Up Charge | $30.00 |
| Arrears Certificate | $15.00 |
| Returned Cheque Charge | $15.00 + bank charges |

Other revenues include miscellaneous revenues related to distribution and generation upgrades that are part of the regulated business, but are aspects of Remotes' work governed by the Electrification Agreements and funded through Indigenous and Northern Affairs Canada ("INAC"). Under those agreements, INAC is responsible for funding changes to the distribution and generation system associated with load growth. Miscellaneous Generation revenues reflect payments from INAC/First Nations for work performed on upgrades and are discussed in the DSP. Miscellaneous Distribution revenues relate to differences from the fixed price charged for connections and the actual cost to perform that work and are also discussed in the DSP.

**Table 2**

**Late Payment and Miscellaneous Revenue ($000s)**

| | **Historic Years** | | | | | **Bridge** | **Test** |
|---|---|---|---|---|---|---|---|
| | **2013 Board Approved** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Energy Late Payment | 314 | 291 | 91 | 297 | 363 | 294 | 312 |
| Non-Energy Late Payment | 25 | 9 | 3 | 6 | 20 | 6 | 6 |
| Specific Service Charge | 0 | 13 | 10 | 14 | 11 | 12 | 12 |
| Miscellaneous Distribution | 25 | 29 | 23 | 65 | 19 | 26 | 26 |
| Miscellaneous Generation | 0 | 0 | 0 | 648 | 229 | 603 | 254 |
| **Total** | **364** | **342** | **127** | **1,030** | **642** | **941** | **610** |

Late payment charges vary based on actual bills outstanding. The Bridge and Test Year forecasts are based on historical information and number of customers. Higher Miscellaneous Generation revenues in 2015 and 2017 reflect the large number of investments INAC made in those years.

## 3.0 EXTERNAL WORK

Remotes performs a small amount of external work for other parties. The main areas of work are: 1) assistance to the Electricity Safety Authority and other parties to facilitate their work in the communities; 2) maintenance activities (streetlights and First Nation-owned generating equipment in Remotes' service territory) and engineering design and assessments related to the connection and integration of renewable generation to Remotes' electricity distribution and generating systems; 3) work for Hydro One Networks and 4) assessments of the Independent Power Authority ("IPA") generating stations (First Nation owned and-operated generating stations in remote communities that Remotes does not serve).

Recent IPA assessments were undertaken to identify defects and improvements required to the Distribution Systems for the community to connect to the grid, and sometimes also included assessments of the generation assets to identify risks and efficiency measures that could be undertaken to improve current operations. Revenues associated with work done for Hydro One Networks under Service Level Agreements (as discussed in Exhibit A, Tab 6, Schedule 1 are also included in external work. Revenues from external work are shown in Table 3 below. Expenses associated with external work are shown in Exhibit D1, Tab 2, Schedule 1.

**Table 3**

**External Work ($000s)**

| **Historic Years** | | | | | **Bridge** | **Test** |
|---|---|---|---|---|---|---|
| **2013 Board Approved** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| 150 | 347 | 367 | 579 | 913 | 389 | 389 |

Higher external revenues in 2015 reflect a study of a potential bio mass project planned by Whitesand First Nation and work undertaken on the Sachigo First Nation Tank Farm. External revenues in 2016 were higher, primarily due to an increase in services performed for Hydro One Networks associated with training and Hydro One Networks' use of Remotes chartered aircraft for flights. Revenues associated with engineering work to design and integrate a planned high penetration wind/solar installation in Fort Severn, a retrofit of the streetlights in Weagamow and the assessment of the distribution and generation assets in Weenusk also contributed to the increased revenues. Revenues from external work in 2017 and 2018 are expected to include assessments of IPA distribution systems in Pikangikum and Wawakapewin.

**Table 4**

**Total Other Revenues ($000s)**

| | **2013 Board Approved** | **Historic Years** | | | | **Bridge** | **Test** |
|---|---|---|---|---|---|---|---|
| | **2013** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Late Payment and Miscellaneous Revenue | 364 | 342 | 127 | 1,030 | 642 | 941 | 610 |
| External Work | 150 | 347 | 367 | 579 | 913 | 389 | 389 |
| **Total** | **514** | **689** | **494** | **1,609** | **1,555** | **1,330** | **999** |

# RURAL AND REMOTE RATE PROTECTION REQUIREMENT

## 1.0 INTRODUCTION

Remotes has two broad categories of customers, Standard A or government customers whose rates have historically been set above cost, and those Residential and General Service customers who benefit from Rural and Remote Rate Protection. These two categories are set out in O. Reg. 442/01, the regulation under the *Ontario Energy Board Act, 1998*, that establishes the rules for Rural and Remote Rate Protection (RRRP). Most of Remotes' customers pay rates that are subsidized by RRRP and are set well below the per kWh cost to serve from diesel fuel.

The revenues to fund the RRRP program are derived from charges to all electricity users in the grid-connected part of the Province. Under current Board-approved processes, the IESO collects the total amount of RRRP and maintains a variance account to track over or under collection of RRRP to meet the program's requirements. The IESO distributes Remotes' OEB-approved share of RRRP revenues in equal installments throughout the year.

Remotes operates under a cost-recovery model applied to achieve an after-tax break-even operating result. Any excess or deficiency in RRRP revenues necessary to break-even is added to, or drawn from, the RRRP Variance Account. Further information about this account can be found in Exhibit H, Tab 1, Schedules 1 to 4. RRRP transfers account for over half of Remotes' revenues each year. RRRP for customers in Remotes' service area is currently set at $32,259K per year.

Sections 4(2) and 4(3) of Regulation 442/01 set out the rules for determining the level of rural and remote rate protection for Remotes' customers as follows:

> "The Board shall calculate the amount by which Hydro One Remote Communities Inc.'s forecasted revenue requirement for the year as approved by the Board exceeds Hydro One Remote Communities Inc.'s forecasted consumer revenues for the year, as approved by the Board."

## 2.0 REVENUE FORECAST FOR OFF-GRID COMMUNITIES

As discussed in Exhibit G1, Tab 1, Schedule 1 Remotes forecasts its customer load annually, based on customer numbers and kWh usage by community and class. This historical data provides the baseline for forecasting revenue usage / kWh sold. Adjustments are made to this baseline data for future years based on average historical growth in usage and historical annual customer changes.

Tables 1 and 2 below show the 2018 load forecast by category and customer class.

**Table 1**
**2018 Non Standard A Load Forecast by Customer Class**
**(From Table 1, Exhibit G1, Tab 1, Schedule 1)**

**Non Standard A**
**Load Forecast Summary**
**(From G1-01-01)**

| | **Residential** | **Seasonal** | **GS 1 Phase** | **GS 3 Phase** | **Streetlight** | **Total** |
|---|---|---|---|---|---|---|
| Effective # of Customers | 2,695 | 147 | 306 | 43 | 8 | 3,199 |
| Average kWh's/Customer | 14,447 | 2,125 | 21,006 | 117,256 | 32,906 | |
| **Total MWh's** | **38,935** | **312** | **6,428** | **5,042** | **263** | **50,980** |

**Table 2**

**2018 Standard A Load Forecast by Customer Class**

**(From Table 2, Exhibit G1, Tab 1, Schedule 1)**

**Standard A**
**Load Forecast Summary**
**(G1-01-01)**

| | **Residential Road Rail** | **Residential Air Access** | **GS Road Rail** | **GS Air Access** | **Total** |
|---|---|---|---|---|---|
| Effective # of Customers | 8 | 135 | 22 | 288 | 453 |
| Average kWh's/Customer | 5,971 | 10,510 | 32,283 | 32,668 | |
| **Total MWh's** | **48** | **1,419** | **710** | **9,408** | **11,585** |

Table 3 shows the Revenue forecast by Standard A and Non Standard A customer categories.

**Table 3**

**2018 Revenue Forecast at Current Rates (in $K)**

| Community | Non Standard A | | Standard A | | Total | |
|---|---|---|---|---|---|---|
| | **MWh** | **Revenue** | **MWh** | **Revenue** | **MWh** | **Revenue** |
| Armstrong | 4,415 | $544 | 508 | $349 | 4,924 | $893 |
| Bearskin Lake | 2,210 | $263 | 616 | $611 | 2,826 | $874 |
| Big Trout Lake | 5,481 | $648 | 840 | $834 | 6,321 | $1,482 |
| Biscotasing | 418 | $73 | - | $0 | 418 | $73 |
| Deer Lake | 4,162 | $498 | 1,061 | $1,053 | 5,223 | $1,551 |
| Fort Severn | 2,149 | $253 | 835 | $828 | 2,984 | $1,081 |
| Gull Bay | 924 | $116 | 249 | $171 | 1,173 | $287 |
| Hillsport | 273 | $37 | - | $0 | 273 | $37 |
| Kasabonika | 4,397 | $517 | 996 | $989 | 5,393 | $1,506 |
| Kingfisher | 2,072 | $237 | 518 | $515 | 2,590 | $752 |
| Lansdowne | 1,391 | $161 | 684 | $679 | 2,075 | $840 |
| Marten Falls | 1,367 | $151 | 628 | $623 | 1,995 | $774 |
| Oba | 230 | $34 | - | $0 | 230 | $34 |
| Sachigo Lake | 2,766 | $321 | 729 | $725 | 3,495 | $1,046 |
| Sandy Lake | 9,857 | $1,192 | 1,990 | $1,975 | 11,847 | $3,167 |
| Sultan | 460 | $66 | - | $0 | 460 | $66 |
| Wapekeka | 2,044 | $247 | 525 | $521 | 2,569 | $768 |
| Weagamow | 4,096 | $488 | 636 | $629 | 4,732 | $1,117 |
| Webequie | 2,268 | $266 | 770 | $763 | 3,038 | $1,029 |
| **Total** | **50,980** | **$6,112** | **11,585** | **$11,265** | **62,566** | **$17,377** |

Table 4 shows the revenue forecast by customer category at proposed 2018 rates with a May 1, 2018 implementation date.

**Table 4**

**2018 Revenue Forecast at 2018 Proposed Rates (in $K)**

| **Community** | **Non Standard A** | | **Standard A** | | **Total** | |
|---|---|---|---|---|---|---|
| | **MWh** | **Revenue** | **MWh** | **Revenue** | **MWh** | **Revenue** |
| Armstrong | 4,415 | $551 | 508 | $353 | 4,924 | $904 |
| Bearskin Lake | 2,210 | $266 | 616 | $620 | 2,826 | $886 |
| Big Trout Lake | 5,481 | $656 | 840 | $846 | 6,321 | $1,502 |
| Biscotasing | 418 | $74 | - | $0 | 418 | $74 |
| Deer Lake | 4,162 | $504 | 1,061 | $1,068 | 5,223 | $1,572 |
| Fort Severn | 2,149 | $256 | 835 | $840 | 2,984 | $1,096 |
| Gull Bay | 924 | $117 | 249 | $173 | 1,173 | $290 |
| Hillsport | 273 | $38 | - | $0 | 273 | $38 |
| Kasabonika | 4,397 | $523 | 996 | $1,003 | 5,393 | $1,526 |
| Kingfisher | 2,072 | $240 | 518 | $522 | 2,590 | $762 |
| Lansdowne | 1,391 | $163 | 684 | $689 | 2,075 | $852 |
| Marten Falls | 1,367 | $153 | 628 | $632 | 1,995 | $785 |
| Oba | 230 | $34 | - | $0 | 230 | $34 |
| Sachigo Lake | 2,766 | $325 | 729 | $735 | 3,495 | $1,060 |
| Sandy Lake | 9,857 | $1,206 | 1,990 | $2,004 | 11,847 | $3,210 |
| Sultan | 460 | $67 | - | $0 | 460 | $67 |
| Wapekeka | 2,044 | $250 | 525 | $528 | 2,569 | $778 |
| Weagamow | 4,096 | $494 | 636 | $638 | 4,732 | $1,132 |
| Webequie | 2,268 | $270 | 770 | $774 | 3,038 | $1,044 |
| **Total** | **50,980** | **$6,187** | **11,585** | **$11,425** | **62,566** | **$17,612** |

The revenue from proposed rates is shown with a May 1, 2018 implementation date. The proposed increase has been pro-rated to show this implementation date.

## 3.0 FORECAST RRRP REQUIREMENT

**Table 5**

**Forecasted RRRP Requirement (in $K)**

| **Item** | |
|---|---|
| 2018 Revenue Requirement | **$56,689** |
| Less: 2018 Revenue from Customer Rates | **($17,612)** |
| Other Revenues | **($999)** |
| **Annual RRRP Level for 2018** | **$38,078** |
| **Recovery of Balance of RRRP Variance acct** | **$962** |
| **Total RRRP Level for 2018** | **$39,040** |

# CUSTOMER BILL IMPACTS

## 1.0 INTRODUCTION

The impacts of the proposed changes for Remotes' current customers are shown in Tables 1 to 4 below. The rates have been increased by 1.8%: the total bill impacts may differ slightly from 1.8% because the rates levied to customers are rounded at the appropriate decimal place (four for kWh charges and two for service charges). In this application, the bill impacts for all customer classes will be less than 10% per year. Bill impacts for low volume residential customers, for the monthly service charge will not rise by more than $4 per year due to the rate design change, and the total bill impact, reflecting all proposed changes in the application, will not exceed 10%. For this reason, no bill impact mitigation plan is required.

## 2.0 NON STANDARD A CUSTOMERS

### 2.1 Residential Year Round (R2)

The Year-Round Residential classification applies to a customer's principal residence and may include additional buildings served through the same meter, provided they are not rental income units.

To be classified as year-round residential, all of the following criteria must be met:

(1) Occupants must state that this is their principal residence for the purposes of the *Income Tax Act*;
(2) The occupant must live in this residence for at least eight months of the year;
(3) The address of this residence must appear on the occupant's electrical bill, driver's license, credit card invoice, etc.;

(4) Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for that purpose at the address of this residence.

Table 1 below, shows the percentage change in monthly bills of the proposed 2018 rates compared to the current 2017 rates. The analysis is based on the total bill, including a monthly service charge and HST.

**Table 1**

**Bill Impacts for Residential (R2) Customers**

| RESIDENTIAL YEAR ROUND (R2) | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST** | **Proposed Bill** | **Proposed Bill with HST** | **Percentage Change** |
| **100** | $28.60 | $30.03 | $29.11 | $30.57 | 1.78% |
| **250** | $42.33 | $44.44 | $43.08 | $45.23 | 1.77% |
| **500** | $65.20 | $68.46 | $66.35 | $69.67 | 1.76% |
| **750** | $88.08 | $92.48 | $89.63 | $94.11 | 1.76% |
| **1000** | $110.95 | $116.50 | $112.90 | $118.55 | 1.76% |
| **2000** | $233.05 | $244.70 | $237.20 | $249.06 | 1.78% |
| **2500** | $294.10 | $308.81 | $299.35 | $314.32 | 1.79% |

## 2.2 Residential Seasonal (R4)

This classification is comprised of cottages, chalets and camps or any other residential service not meeting the year-round residential criteria. Table 2 gives a comparison of current versus proposed rates for Residential Seasonal customers. The analysis is based on the total bill, including a monthly service charge.

**Table 2**

**Bill Impacts for Residential Seasonal (R4) Customers**

| RESIDENTIAL SEASONAL (R4) | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST (includes rebate)** | **Proposed Bill** | **Proposed Bill with HST (includes rebate)** | **Percentage Change** |
| **100** | $42.02 | $44.12 | $42.77 | $44.91 | 1.78% |
| **250** | $55.75 | $58.53 | $56.74 | $59.57 | 1.78% |
| **500** | $78.62 | $82.55 | $80.01 | $84.01 | 1.77% |
| **750** | $101.50 | $106.57 | $103.29 | $108.45 | 1.76% |
| **1000** | $124.37 | $130.59 | $126.56 | $132.89 | 1.76% |
| **2000** | $246.47 | $258.79 | $250.86 | $263.40 | 1.78% |

## 2.3 General Service Single Phase

This classification applies to any non-Standard A service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative and auxiliary services. It also includes combination services where one property has a variety of uses and for all multiple services except residential. Single Phase service uses single phase power. The bill analysis is based on the total bill, including a service charge.

**Table 3**

**Bill Impacts for General Service Single Phase (G1)**

| GENERAL SERVICE SINGLE PHASE (G1) | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST (includes rebate)** | **Proposed Bill** | **Proposed Bill with HST (includes rebate)** | **Percentage Change** |
| **1000** | $135.66 | $142.44 | $138.06 | $144.96 | 1.77% |
| **2000** | $238.26 | $250.17 | $242.46 | $254.58 | 1.76% |
| **3000** | $340.86 | $357.90 | $346.86 | $364.20 | 1.76% |
| **5000** | $546.06 | $573.36 | $555.66 | $583.44 | 1.76% |

## 2.4 General Service Three Phase

This classification applies to non-residential customers who use three phase power. The bill analysis is based on the total bill, including a service charge.

**Table 4**

**Bill Impacts for General Service (G3)**

| GENERAL SERVICE THREE PHASE (G3) | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST (includes rebate)** | **Proposed Bill** | **Proposed Bill with HST (includes rebate)** | **Percentage Change** |
| **2000** | $246.59 | $258.92 | $250.94 | $263.49 | 1.76% |
| **3000** | $349.19 | $366.65 | $355.34 | $373.11 | 1.76% |
| **5000** | $554.39 | $582.11 | $564.14 | $592.35 | 1.76% |
| **10,000** | $1,067.39 | $1,120.76 | $1,086.14 | $1,140.45 | 1.76% |

### 2.5 Street Lighting

This classification applies to unmetered street lights. The energy consumption for streetlights is based on Remotes' profile for street lighting load, which provides the amount of time each month that the street lights are operating. The bill analysis is based on the total bill.

**Table 5**
**Rate Impacts for Streetlights**

| STREET LIGHTING | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST (includes rebate)** | **Proposed Bill** | **Proposed Bill with HST (includes rebate)** | **Percentage Change** |
| **500** | $50.85 | $53.39 | $51.75 | $54.34 | 1.77% |
| **2000** | $203.40 | $213.57 | $207.00 | $217.35 | 1.77% |
| **4000** | $406.80 | $427.14 | $414.00 | $434.70 | 1.77% |

## 3.0 STANDARD A CUSTOMERS

This classification is applicable to all Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.;
- social housing;
- a recreational or sports facility;
- a radio, television or cable television facility; and
- a library.

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source.

### 3.1 Standard A Residential Road/Rail

This classification applies to residential customers who occupy premises funded in whole or in part by government, and who live in communities accessible by all season roads and by rail. The bill analysis is based on the total bill, including a service charge.

**Table 6**
**Bill Impacts for Standard A Residential Road/Rail**

| STANDARD A RESIDENTIAL ROAD/RAIL | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST (includes rebate)** | **Proposed Bill** | **Proposed Bill with HST (includes rebate)** | **Percentage Change** |
| **100** | $60.25 | $63.26 | $61.33 | $64.40 | 1.79% |
| **250** | $150.63 | $158.16 | $153.33 | $160.99 | 1.79% |
| **500** | $322.73 | $338.86 | $328.53 | $344.95 | 1.80% |
| **750** | $494.83 | $519.57 | $503.73 | $528.91 | 1.80% |
| **1000** | $666.93 | $700.27 | $678.93 | $712.87 | 1.80% |
| **2000** | $1,355.33 | $1,423.09 | $1,379.73 | $1,448.71 | 1.80% |

### 3.2 Standard A Residential Air Access

This classification applies to residential customers who occupy premises funded in whole or in part by government, and who live in communities that are not accessible by year-round roads. The bill analysis is based on the total bill.

**Table 7**

**Bill Impacts for Standard A Residential Air Access**

| STANDARD A RESIDENTIAL AIR ACCESS | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST (includes rebate)** | **Proposed Bill** | **Proposed Bill with HST (includes rebate)** | **Percentage Change** |
| **250** | $227.40 | $238.77 | $231.50 | $243.08 | 1.80% |
| **500** | $476.28 | $500.09 | $484.85 | $509.09 | 1.80% |
| **750** | $725.15 | $761.41 | $738.20 | $775.11 | 1.80% |
| **1000** | $974.03 | $1,022.73 | $991.55 | $1,041.13 | 1.80% |
| **2000** | $1,969.53 | $2,068.00 | $2,004.95 | $2,105.20 | 1.80% |

### 3.3 Standard A General Service Road/Rail

This classification applies to general service customers who occupy premises funded in whole or in part by government, in communities that are accessible by year-round roads. The bill analysis is based on the total bill.

**Table 8**

**Rate Impacts for Standard A General Service Road/Rail**

| STANDARD A GENERAL SERVICE ROAD RAIL | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST (includes rebate)** | **Proposed Bill** | **Proposed Bill with HST (includes rebate)** | **Percentage Change** |
| **1000** | $688.40 | $722.82 | $700.80 | $735.84 | 1.80% |
| **2000** | $1,376.80 | $1,445.64 | $1,401.60 | $1,471.65 | 1.80% |
| **5000** | $3,442.00 | $3,614.10 | $3,504.00 | $3,679.20 | 1.80% |

## 3.4 Standard A General Service Air Access

This classification applies to general service customers who occupy premises funded in whole or in part by government, in communities that are not accessible by year-round roads. The bill analysis is based on the total bill.

**Table 9**

**Rate Impacts for Standard A General Service Air Access**

| STANDARD A GENERAL SERVICE AIR ACCESS | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST (includes rebate)** | **Proposed Bill** | **Proposed Bill with HST (includes rebate)** | **Percentage Change** |
| **1000** | $995.50 | $1,045.28 | $1,013.40 | $1,064.07 | 1.80% |
| **2000** | $1,991.00 | $2,090.55 | $2,026.80 | $2,128.14 | 1.80% |
| **5000** | $4,977.50 | $5,226.38 | $5,067.00 | $5,320.35 | 1.80% |

## 3.5 Standard A Grid Connected

This classification is applicable to all Standard A customers that are connected to the grid.

**Table 10**

**Rate Impacts for Standard A Grid Connected**

| STANDARD A GRID CONNECTED | | | | | |
|---|---|---|---|---|---|
| **Scenario (kWh)** | **Current Bill** | **Current Bill with HST (includes rebate)** | **Proposed Bill** | **Proposed Bill with HST (includes rebate)** | **Percentage Change** |
| **1000** | $311.90 | $327.50 | $317.50 | $333.38 | 1.80% |
| **2000** | $623.80 | $654.99 | $635.00 | $666.75 | 1.80% |
| **5000** | $1,559.50 | $1,637.48 | $1,587.50 | $1,666.88 | 1.80% |

## Appendix 2-IB
## Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet is to be filled in accordance with the instructions documented in section 2.3.2 of Chapter 2 of the Filing Requirements for Distribution Rate Applications, in terms of one set of tables per customer class.

Color coding for Cells: Data input | Drop-down List | No data entry required | Blank or calculated value

***Distribution Svstem (Total) (Off Grid Communities)***

| | Calendar Year (for 2018 Cost of Service | Customers | | | | Consumption (kWh) [3] | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|---|---|---|---|---|---|
| Historical | 2012 | Actual | 3,530 | | | Actual | 56,124,200 | 56,124,200 | | |
| Historical | 2013 | Actual | 3,513 | Board-approved | 3529 | Actual | 58,628,424 | 58,628,424 | Board-approved | 56,430,591 |
| Historical | 2014 | Actual | 3,546 | | | Actual | 62,338,648 | 62,338,648 | | |
| Historical | 2015 | Actual | 3,530 | | | Actual | 61,100,418 | 61,100,418 | | |
| Historical | 2016 | Actual | 3,554 | | | Actual | 64,439,719 | 64,439,719 | | |
| Bridge Year | 2017 | Forecast | 3,627 | | | Forecast | 61,381,706 | 61,381,706 | | |
| Test Year | 2018 | Forecast | 3,652 | | | Forecast | 62,565,904 | 62,565,904 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved | Year | Year-over-year | | Versus Board-approved |
|---|---|---|---|---|---|---|---|
| | 2012 | | | 2012 | | | |
| | 2013 | -0.5% | | 2013 | 4.5% | 4.5% | |
| | 2014 | 0.9% | | 2014 | 6.3% | 6.3% | |
| | 2015 | -0.5% | | 2015 | -2.0% | -2.0% | |
| | 2016 | 0.7% | | 2016 | 5.5% | 5.5% | |
| | 2017 | 2.1% | | 2017 | | -4.7% | |
| | 2018 | 0.7% | | 2018 | | 1.9% | 10.9% |
| | Geometric Mean | 0.7% | | Geometric Mean | 4.7% | 2.2% | 3.5% |

*Customer Class Analysis (one for each Customer Class, excluding MicroFIT and Standby)*

**1 Customer Class:** Year Round Residential - R2

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

**Customers**

| | Calendar Year (for 2017 Cost of Service | | Customers | | |
|---|---|---|---|---|---|
| Historical | *2012* | Actual | 2,599 | | |
| Historical | *2013* | Actual | 2,582 | Board-approved | 2,595 |
| Historical | *2014* | Actual | 2,616 | | |
| Historical | *2015* | Actual | 2,599 | | |
| Historical | *2016* | Actual | 2,621 | | |
| Bridge Year | *2017* | Forecast | 2,683 | | |
| Test Year | *2018* | Forecast | 2,695 | | |

**Consumption (kWh) [3]**

| | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 34,792,800 | 34,792,800 | | |
| Actual | 36,786,816 | 36,786,816 | Board-approved | 35,125,612 |
| Actual | 38,513,780 | 38,513,780 | | |
| Actual | 38,143,476 | 38,143,476 | | |
| Actual | 40,513,072 | 40,513,072 | | |
| Forecast | 38,493,908 | 38,493,908 | | |
| Forecast | 38,935,222 | 38,935,222 | | |

**Consumption (kWh) per Customer**

| | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 13,387 | 13,387 | | |
| Actual | 14,247 | 14,247 | Board-approved | 13,536 |
| Actual | 14,722 | 14,722 | | |
| Actual | 14,676 | 14,676 | | |
| Actual | 15,457 | 15,457 | | |
| Forecast | 14,347 | 14,347 | | |
| Forecast | 14,447 | 14,447 | | |

**Variance Analysis**

| Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|
| *2012* | | |
| *2013* | -0.7% | |
| *2014* | 1.3% | |
| *2015* | -0.6% | |
| *2016* | 0.8% | |
| *2017* | 2.4% | |
| *2018* | 0.4% | 3.9% |
| Geometric Mean | 0.7% | 1.3% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| *2012* | | | |
| *2013* | 5.7% | 5.7% | |
| *2014* | 4.7% | 4.7% | |
| *2015* | -1.0% | -1.0% | |
| *2016* | 6.2% | 6.2% | |
| *2017* | | -5.0% | |
| *2018* | | 1.1% | 10.8% |
| Geometric Mean | 5.2% | 2.3% | 3.5% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| *2012* | | | |
| *2013* | 6.4% | 6.4% | |
| *2014* | 3.3% | 3.3% | |
| *2015* | -0.3% | -0.3% | |
| *2016* | 5.3% | 5.3% | |
| *2017* | | -7.2% | |
| *2018* | | 0.7% | 6.7% |
| Geometric Mean | 4.9% | 1.5% | 2.2% |

**Revenues**

| | Calendar Year (for 2017 Cost of Service | | Revenues | | |
|---|---|---|---|---|---|
| Historical | *2012* | Actual | $ 3,752,574 | | |
| Historical | *2013* | Actual | $ 4,009,719 | Board-approved | $ 3,951,061 |
| Historical | *2014* | Actual | $ 4,404,317 | | |
| Historical | *2015* | Actual | $ 4,405,018 | | |
| Historical | *2016* | Actual | $ 4,724,056 | | |
| Bridge Year (Foreca | *2017* | Forecast | $ 4,567,706 | | |
| Test Year (Forecast | *2018* | Forecast | $ 4,708,287 | | |

**Variance Analysis**

| Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|
| *2012* | | |
| *2013* | 6.9% | |
| *2014* | 9.8% | |
| *2015* | 0.0% | |
| *2016* | 7.2% | |
| *2017* | -3.3% | |
| *2018* | 3.1% | 19.2% |
| Geometric Mean | 4.6% | 6.0% |

2 **Customer Class:** Seasonal Residential - R4

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

| | Calendar Year (for 2017 Cost of Service | Customers | | | |
|---|---|---|---|---|---|
| Historical | *2012* | Actual | 154 | | |
| Historical | *2013* | Actual | 148 | Board-approved | 164 |
| Historical | *2014* | Actual | 146 | | |
| Historical | *2015* | Actual | 154 | | |
| Historical | *2016* | Actual | 146 | | |
| Bridge Year | *2017* | Forecast | 146 | | |
| Test Year | *2018* | Forecast | 147 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | *2012* | | |
| | *2013* | -3.9% | |
| | *2014* | -1.4% | |
| | *2015* | 5.5% | |
| | *2016* | -5.2% | |
| | *2017* | 0.0% | |
| | *2018* | 0.7% | -10.4% |
| | Geometric Mean | -0.9% | -3.6% |

| Consumption (kWh) (3) | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 339,000 | 339,000 | | |
| Actual | 291,477 | 291,477 | Board-approved | 353,073 |
| Actual | 293,871 | 293,871 | | |
| Actual | 315,414 | 315,414 | | |
| Actual | 370,225 | 370,225 | | |
| Forecast | 310,541 | 310,541 | | |
| Forecast | 312,406 | 312,406 | | |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| *2012* | | | |
| *2013* | -14.0% | -14.0% | |
| *2014* | 0.8% | 0.8% | |
| *2015* | 7.3% | 7.3% | |
| *2016* | 17.4% | 17.4% | |
| *2017* | | -16.1% | |
| *2018* | | 0.6% | -11.5% |
| Geometric Mean | 3.0% | -1.6% | -4.0% |

| Consumption (kWh) per Customer | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 2,201 | 2,201 | | |
| Actual | 1,969 | 1,969 | Board-approved | 2,153 |
| Actual | 2,013 | 2,013 | | |
| Actual | 2,048 | 2,048 | | |
| Actual | 2,536 | 2,536 | | |
| Forecast | 2,127 | 2,127 | | |
| Forecast | 2,125 | 2,125 | | |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| *2012* | | | |
| *2013* | -10.5% | -10.5% | |
| *2014* | 2.2% | 2.2% | |
| *2015* | 1.8% | 1.8% | |
| *2016* | 23.8% | 23.8% | |
| *2017* | | -16.1% | |
| *2018* | | -0.1% | -1.3% |
| Geometric Mean | 4.8% | -0.7% | -0.4% |

| | Calendar Year (for 2017 Cost of Service | Revenues | | | |
|---|---|---|---|---|---|
| Historical | *2012* | Actual | $ 81,489 | | |
| Historical | *2013* | Actual | $ 67,827 | Board-approved | $ 80,582 |
| Historical | *2014* | Actual | $ 79,283 | | |
| Historical | *2015* | Actual | $ 83,664 | | |
| Historical | *2016* | Actual | $ 105,980 | | |
| Bridge Year (Foreca | *2017* | Forecast | $ 85,592 | | |
| Test Year (Forecast | *2018* | Forecast | $ 87,433 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | *2012* | | |
| | *2013* | -16.8% | |
| | *2014* | 16.9% | |
| | *2015* | 5.5% | |
| | *2016* | 26.7% | |
| | *2017* | -19.2% | |
| | *2018* | 2.2% | 8.5% |
| | Geometric Mean | 1.4% | 2.8% |

**3 Customer Class:** General Service Single Phase -G1

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

| | Calendar Year (for 2017 Cost of Service) | Customers | | | |
|---|---|---|---|---|---|
| Historical | *2012* | Actual | 289 | | |
| Historical | *2013* | Actual | 292 | Board-approved | 279 |
| Historical | *2014* | Actual | 298 | | |
| Historical | *2015* | Actual | 296 | | |
| Historical | *2016* | Actual | 298 | | |
| Bridge Year | *2017* | Forecast | 302 | | |
| Test Year | *2018* | Forecast | 306 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | *2012* | | |
| | *2013* | 1.0% | |
| | *2014* | 2.1% | |
| | *2015* | -0.7% | |
| | *2016* | 0.7% | |
| | *2017* | 1.3% | |
| | *2018* | 1.3% | 9.7% |
| | Geometric Mean | 1.1% | 3.1% |

| Consumption (kWh) [(3)] | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 8,449,500 | 8,449,500 | | |
| Actual | 7,263,281 | 7,263,281 | Board-approved | 5,648,114 |
| Actual | 6,361,651 | 6,361,651 | | |
| Actual | 6,395,526 | 6,395,526 | | |
| Actual | 6,225,305 | 6,225,305 | | |
| Forecast | 5,960,122 | 5,960,122 | | |
| Forecast | 6,427,846 | 6,427,846 | | |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| *2012* | | | |
| *2013* | -14.0% | -14.0% | |
| *2014* | -12.4% | -12.4% | |
| *2015* | 0.5% | 0.5% | |
| *2016* | -2.7% | -2.7% | |
| *2017* | | -4.3% | |
| *2018* | | 7.8% | 13.8% |
| Geometric Mean | -9.7% | -5.3% | 4.4% |

| Consumption (kWh) per Customer | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 29,237 | 29,237 | | |
| Actual | 24,874 | 24,874 | Board-approved | 20,244 |
| Actual | 21,348 | 21,348 | | |
| Actual | 21,607 | 21,607 | | |
| Actual | 20,890 | 20,890 | | |
| Forecast | 19,736 | 19,736 | | |
| Forecast | 21,006 | 21,006 | | |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| *2012* | | | |
| *2013* | -14.9% | -14.9% | |
| *2014* | -14.2% | -14.2% | |
| *2015* | 1.2% | 1.2% | |
| *2016* | -3.3% | -3.3% | |
| *2017* | | -5.5% | |
| *2018* | | 6.4% | 3.8% |
| Geometric Mean | -10.6% | -6.4% | 1.2% |

| | Calendar Year (for 2017 Cost of Service) | Revenues | | | |
|---|---|---|---|---|---|
| Historical | *2012* | Actual | $ 1,255,393 | | |
| Historical | *2013* | Actual | $ 806,194 | Board-approved | $ 653,958 |
| Historical | *2014* | Actual | $ 756,269 | | |
| Historical | *2015* | Actual | $ 767,529 | | |
| Historical | *2016* | Actual | $ 761,048 | | |
| Bridge Year (Foreca | *2017* | Forecast | $ 779,319 | | |
| Test Year (Forecast | *2018* | Forecast | $ 810,997 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | *2012* | | |
| | *2013* | -35.8% | |
| | *2014* | -6.2% | |
| | *2015* | 1.5% | |
| | *2016* | -0.8% | |
| | *2017* | 2.4% | |
| | *2018* | 4.1% | 24.0% |
| | Geometric Mean | -8.4% | 7.4% |

4 **Customer Class:** General Service Three Phase -G3 | Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

| | Calendar Year (for 2017 Cost of Service | | Customers | | |
|---|---|---|---|---|---|
| Historical | 2012 | Actual | 47 | | |
| Historical | 2013 | Actual | 40 | Board-approved | 27 |
| Historical | 2014 | Actual | 40 | | |
| Historical | 2015 | Actual | 40 | | |
| Historical | 2016 | Actual | 42 | | |
| Bridge Year | 2017 | Forecast | 42 | | |
| Test Year | 2018 | Forecast | 43 | | |

| | Consumption (kWh) [3] | | | |
|---|---|---|---|---|
| | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
| Actual | 1,186,500 | 1,186,500 | | |
| Actual | 2,957,760 | 2,957,760 | Board-approved | 3,615,314 |
| Actual | 4,984,080 | 4,984,080 | | |
| Actual | 4,693,610 | 4,693,610 | | |
| Actual | 4,967,450 | 4,967,450 | | |
| Forecast | 4,942,563 | 4,942,563 | | |
| Forecast | 5,042,005 | 5,042,005 | | |

| | Consumption (kWh) per Customer | | | |
|---|---|---|---|---|
| | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
| Actual | 25,245 | 25,245 | | |
| Actual | 73,944 | 73,944 | Board-approved | 133,901 |
| Actual | 124,602 | 124,602 | | |
| Actual | 117,340 | 117,340 | | |
| Actual | 118,273 | 118,273 | | |
| Forecast | 117,680 | 117,680 | | |
| Forecast | 117,256 | 117,256 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | 2012 | | |
| | 2013 | -14.9% | |
| | 2014 | 0.0% | |
| | 2015 | 0.0% | |
| | 2016 | 5.0% | |
| | 2017 | 0.0% | |
| | 2018 | 2.4% | 59.3% |
| | Geometric Mean | -1.8% | 16.8% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| 2012 | | | |
| 2013 | 149.3% | 149.3% | |
| 2014 | 68.5% | 68.5% | |
| 2015 | -5.8% | -5.8% | |
| 2016 | 5.8% | 5.8% | |
| 2017 | | -0.5% | |
| 2018 | | 2.0% | 39.5% |
| Geometric Mean | 61.2% | 33.6% | 11.7% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| 2012 | | | |
| 2013 | 192.9% | 192.9% | |
| 2014 | 68.5% | 68.5% | |
| 2015 | -5.8% | -5.8% | |
| 2016 | 0.8% | 0.8% | |
| 2017 | | -0.5% | |
| 2018 | | -0.4% | -12.4% |
| Geometric Mean | 67.3% | 36.0% | -4.3% |

| | Calendar Year (for 2017 Cost of Service | | Revenues | | |
|---|---|---|---|---|---|
| Historical | 2012 | Actual | $ 114,691 | | |
| Historical | 2013 | Actual | $ 294,894 | Board-approved | $ 358,506 |
| Historical | 2014 | Actual | $ 514,187 | | |
| Historical | 2015 | Actual | $ 493,725 | | |
| Historical | 2016 | Actual | $ 533,049 | | |
| Bridge Year (Foreca | 2017 | Forecast | $ 532,503 | | |
| Test Year (Forecast | 2018 | Forecast | $ 553,136 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | 2012 | | |
| | 2013 | 157.1% | |
| | 2014 | 74.4% | |
| | 2015 | -4.0% | |
| | 2016 | 8.0% | |
| | 2017 | -0.1% | |
| | 2018 | 3.9% | 54.3% |
| | Geometric Mean | 37.0% | 15.6% |

**5 Customer Class:** Street Lighting

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

| | Calendar Year (for 2017 Cost of Service | | Customers | | |
|---|---|---|---|---|---|
| Historical | 2012 | Actual | 6 | | |
| Historical | 2013 | Actual | 6 | Board-approved | 6 |
| Historical | 2014 | Actual | 7 | | |
| Historical | 2015 | Actual | 6 | | |
| Historical | 2016 | Actual | 7 | | |
| Bridge Year | 2017 | Forecast | 7 | | |
| Test Year | 2018 | Forecast | 8 | | |

| | Calendar Year | | Consumption (kWh) [3] Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|---|---|
| Historical | 2012 | Actual | 224,500 | 224,500 | | |
| Historical | 2013 | Actual | 235,767 | 235,767 | Board-approved | 224,019 |
| Historical | 2014 | Actual | 275,928 | 275,928 | | |
| Historical | 2015 | Actual | 291,955 | 291,955 | | |
| Historical | 2016 | Actual | 276,217 | 276,217 | | |
| Bridge Year | 2017 | Forecast | 263,244 | 263,244 | | |
| Test Year | 2018 | Forecast | 263,245 | 263,245 | | |

| | Calendar Year | | Consumption (kWh) per Customer Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|---|---|
| Historical | 2012 | Actual | 37,417 | 37,417 | | |
| Historical | 2013 | Actual | 39,295 | 39,295 | Board-approved | 37,336 |
| Historical | 2014 | Actual | 39,418 | 39,418 | | |
| Historical | 2015 | Actual | 48,659 | 48,659 | | |
| Historical | 2016 | Actual | 39,460 | 39,460 | | |
| Bridge Year | 2017 | Forecast | 37,606 | 37,606 | | |
| Test Year | 2018 | Forecast | 32,906 | 32,906 | | |

**Variance Analysis**

| Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|
| 2012 | | |
| 2013 | 0.0% | |
| 2014 | 16.7% | |
| 2015 | -14.3% | |
| 2016 | 16.7% | |
| 2017 | 0.0% | |
| 2018 | 14.3% | 33.3% |
| Geometric Mean | 5.9% | 10.1% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| 2012 | | | |
| 2013 | 5.0% | 5.0% | |
| 2014 | 17.0% | 17.0% | |
| 2015 | 5.8% | 5.8% | |
| 2016 | -5.4% | -5.4% | |
| 2017 | | -4.7% | |
| 2018 | | 0.0% | 17.5% |
| Geometric Mean | 7.2% | 3.2% | 5.5% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| 2012 | | | |
| 2013 | 5.0% | 5.0% | |
| 2014 | 0.3% | 0.3% | |
| 2015 | 23.4% | 23.4% | |
| 2016 | -18.9% | -18.9% | |
| 2017 | | -4.7% | |
| 2018 | | -12.5% | -11.9% |
| Geometric Mean | 1.8% | -2.5% | -4.1% |

| | Calendar Year (for 2017 Cost of Service | | Revenues | | |
|---|---|---|---|---|---|
| Historical | 2011 | Actual | $ 20,558 | | |
| Historical | 2012 | Actual | $ 21,772 | | $ 20,941 |
| Historical | 2013 | Actual | $ 26,451 | Board-approved | |
| Historical | 2014 | Actual | $ 28,630 | | |
| Historical | 2015 | Actual | $ 27,472 | | |
| Bridge Year (Foreca | 2016 | Forecast | $ 26,598 | | |
| Test Year (Forecast | 2017 | Forecast | $ 27,088 | | |

**Variance Analysis**

| Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|
| 2011 | | |
| 2012 | 5.9% | |
| 2013 | 21.5% | |
| 2014 | 8.2% | |
| 2015 | -4.0% | |
| 2016 | -3.2% | |
| 2017 | 1.8% | 29.4% |
| Geometric Mean | 5.7% | 9.0% |

**6 Customer Class:** Standard A Residential Road/Rail

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

| | Calendar Year (for 2017 Cost of Service) | Customers | | | |
|---|---|---|---|---|---|
| **Historical** | *2012* | Actual | 9 | | |
| **Historical** | *2013* | Actual | 9 | Board-approved | 12 |
| **Historical** | *2014* | Actual | 8 | | |
| **Historical** | *2015* | Actual | 9 | | |
| **Historical** | *2016* | Actual | 8 | | |
| **Bridge Year** | *2017* | Forecast | 8 | | |
| **Test Year** | *2018* | Forecast | 8 | | |

| | Calendar Year (for 2017 Cost of Service) | Consumption (kWh) [3] | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|---|---|
| **Historical** | *2012* | Actual | 44,200 | 44,200 | | |
| **Historical** | *2013* | Actual | 41,879 | 41,879 | Board-approved | 65,568 |
| **Historical** | *2014* | Actual | 46,009 | 46,009 | | |
| **Historical** | *2015* | Actual | 44,235 | 44,235 | | |
| **Historical** | *2016* | Actual | 52,698 | 52,698 | | |
| **Bridge Year** | *2017* | Forecast | 47,546 | 47,546 | | |
| **Test Year** | *2018* | Forecast | 47,771 | 47,771 | | |

| | Calendar Year (for 2017 Cost of Service) | Consumption (kWh) per Customer | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|---|---|
| **Historical** | *2012* | Actual | 4,911 | 4,911 | | |
| **Historical** | *2013* | Actual | 4,653 | 4,653 | Board-approved | 5,464 |
| **Historical** | *2014* | Actual | 5,751 | 5,751 | | |
| **Historical** | *2015* | Actual | 4,915 | 4,915 | | |
| **Historical** | *2016* | Actual | 6,587 | 6,587 | | |
| **Bridge Year** | *2017* | Forecast | 5,943 | 5,943 | | |
| **Test Year** | *2018* | Forecast | 5,971 | 5,971 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | *2012* | | |
| | *2013* | 0.0% | |
| | *2014* | -11.1% | |
| | *2015* | 12.5% | |
| | *2016* | -11.1% | |
| | *2017* | 0.0% | |
| | *2018* | 0.0% | -33.3% |
| | Geometric Mean | -2.3% | -12.6% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| *2012* | | | |
| *2013* | -5.3% | -5.3% | |
| *2014* | 9.9% | 9.9% | |
| *2015* | -3.9% | -3.9% | |
| *2016* | 19.1% | 19.1% | |
| *2017* | | -9.8% | |
| *2018* | | 0.5% | -27.1% |
| Geometric Mean | 6.0% | 1.6% | -10.0% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| *2012* | | | |
| *2013* | -5.3% | -5.3% | |
| *2014* | 23.6% | 23.6% | |
| *2015* | -14.5% | -14.5% | |
| *2016* | 34.0% | 34.0% | |
| *2017* | | -9.8% | |
| *2018* | | 0.5% | 9.3% |
| Geometric Mean | 10.3% | 4.0% | 3.0% |

| | Calendar Year (for 2017 Cost of Service) | Revenues | | | |
|---|---|---|---|---|---|
| **Historical** | *2012* | Actual | $ 20,230 | | |
| **Historical** | *2013* | Actual | $ 24,350 | Board-approved | $ 38,625 |
| **Historical** | *2014* | Actual | $ 28,258 | | |
| **Historical** | *2015* | Actual | $ 27,598 | | |
| **Historical** | *2016* | Actual | $ 33,385 | | |
| **Bridge Year (Foreca** | *2017* | Forecast | $ 30,555 | | |
| **Test Year (Forecast** | *2018* | Forecast | $ 31,314 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | *2012* | | |
| | *2013* | 20.4% | |
| | *2014* | 16.0% | |
| | *2015* | -2.3% | |
| | *2016* | 21.0% | |
| | *2017* | -8.5% | |
| | *2018* | 2.5% | -18.9% |
| | Geometric Mean | 9.1% | -6.8% |

**7 Customer Class:** Standard A Residential Air Access

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

| | Calendar Year (for 2017 Cost of Service) | Customers | | | |
|---|---|---|---|---|---|
| Historical | 2012 | Actual | 106 | | |
| Historical | 2013 | Actual | 119 | Board-approved | 114 |
| Historical | 2014 | Actual | 120 | | |
| Historical | 2015 | Actual | 106 | | |
| Historical | 2016 | Actual | 125 | | |
| Bridge Year | 2017 | Forecast | 130 | | |
| Test Year | 2018 | Forecast | 135 | | |

| Consumption (kWh) [3] | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 1,331,700 | 1,331,700 | | |
| Actual | 1,216,181 | 1,216,181 | Board-approved | 1,289,644 |
| Actual | 1,305,644 | 1,305,644 | | |
| Actual | 1,301,291 | 1,301,291 | | |
| Actual | 1,401,454 | 1,401,454 | | |
| Forecast | 1,358,699 | 1,358,699 | | |
| Forecast | 1,418,887 | 1,418,887 | | |

| Consumption (kWh) per Customer | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 12,563 | 12,563 | | |
| Actual | 10,220 | 10,220 | Board-approved | 11,313 |
| Actual | 10,880 | 10,880 | | |
| Actual | 12,276 | 12,276 | | |
| Actual | 11,212 | 11,212 | | |
| Forecast | 10,452 | 10,452 | | |
| Forecast | 10,510 | 10,510 | | |

**Variance Analysis**

| Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|
| 2012 | | |
| 2013 | 12.3% | |
| 2014 | 0.8% | |
| 2015 | -11.7% | |
| 2016 | 17.9% | |
| 2017 | 4.0% | |
| 2018 | 3.8% | 18.4% |
| Geometric Mean | 5.0% | 5.8% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| 2012 | | | |
| 2013 | -8.7% | -8.7% | |
| 2014 | 7.4% | 7.4% | |
| 2015 | -0.3% | -0.3% | |
| 2016 | 7.7% | 7.7% | |
| 2017 | | -3.1% | |
| 2018 | | 4.4% | 10.0% |
| Geometric Mean | 1.7% | 1.3% | 3.2% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| 2012 | | | |
| 2013 | -18.7% | -18.7% | |
| 2014 | 6.5% | 6.5% | |
| 2015 | 12.8% | 12.8% | |
| 2016 | -8.7% | -8.7% | |
| 2017 | | -6.8% | |
| 2018 | | 0.6% | -7.1% |
| Geometric Mean | -3.7% | -3.5% | -2.4% |

| | Calendar Year (for 2017 Cost of Service) | Revenues | | | |
|---|---|---|---|---|---|
| Historical | 2012 | Actual | $ 1,150,446 | | |
| Historical | 2013 | Actual | $ 1,069,141 | Board-approved | $ 1,153,924 |
| Historical | 2014 | Actual | $ 1,206,381 | | |
| Historical | 2015 | Actual | $ 1,216,551 | | |
| Historical | 2016 | Actual | $ 1,326,847 | | |
| Bridge Year (Foreca | 2017 | Forecast | $ 1,309,319 | | |
| Test Year (Forecast | 2018 | Forecast | $ 1,396,850 | | |

**Variance Analysis**

| Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|
| 2012 | | |
| 2013 | -7.1% | |
| 2014 | 12.8% | |
| 2015 | 0.8% | |
| 2016 | 9.1% | |
| 2017 | -1.3% | |
| 2018 | 6.7% | 21.1% |
| Geometric Mean | 4.0% | 6.6% |

8 **Customer Class:** Standard A General Service Road/Rail

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

| | Calendar Year (for 2017 Cost of Service | Customers | | | |
|---|---|---|---|---|---|
| Historical | 2012 | Actual | 28 | | |
| Historical | 2013 | Actual | 24 | Board-approved | 27 |
| Historical | 2014 | Actual | 21 | | |
| Historical | 2015 | Actual | 28 | | |
| Historical | 2016 | Actual | 22 | | |
| Bridge Year | 2017 | Forecast | 22 | | |
| Test Year | 2018 | Forecast | 22 | | |

| Consumption (kWh) [3] | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 625,200 | 625,200 | | |
| Actual | 610,901 | 610,901 | Board-approved | 648,610 |
| Actual | 714,942 | 714,942 | | |
| Actual | 740,650 | 740,650 | | |
| Actual | 728,847 | 728,847 | | |
| Forecast | 706,570 | 706,570 | | |
| Forecast | 710,230 | 710,230 | | |

| Consumption (kWh) per Customer | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 22,329 | 22,329 | | |
| Actual | 25,454 | 25,454 | Board-approved | 24,023 |
| Actual | 34,045 | 34,045 | | |
| Actual | 26,452 | 26,452 | | |
| Actual | 33,129 | 33,129 | | |
| Forecast | 32,117 | 32,117 | | |
| Forecast | 32,283 | 32,283 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | 2012 | | |
| | 2013 | -14.3% | |
| | 2014 | -12.5% | |
| | 2015 | 33.3% | |
| | 2016 | -21.4% | |
| | 2017 | 0.0% | |
| | 2018 | 0.0% | -18.5% |
| | Geometric Mean | -4.7% | -6.6% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| 2012 | | | |
| 2013 | -2.3% | -2.3% | |
| 2014 | 17.0% | 17.0% | |
| 2015 | 3.6% | 3.6% | |
| 2016 | -1.6% | -1.6% | |
| 2017 | | -3.1% | |
| 2018 | | 0.5% | 9.5% |
| Geometric Mean | 5.2% | 2.6% | 3.1% |

| Year | Year-over-year | | Test Year Versus Board-approved |
|---|---|---|---|
| 2012 | | | |
| 2013 | 14.0% | 14.0% | |
| 2014 | 33.7% | 33.7% | |
| 2015 | -22.3% | -22.3% | |
| 2016 | 25.2% | 25.2% | |
| 2017 | | -3.1% | |
| 2018 | | 0.5% | 34.4% |
| Geometric Mean | 14.1% | 7.7% | 10.4% |

| | Calendar Year (for 2017 Cost of Service | Revenues | | | |
|---|---|---|---|---|---|
| Historical | 2012 | Actual | $ 302,370 | | |
| Historical | 2013 | Actual | $ 380,400 | Board-approved | $ 410,733 |
| Historical | 2014 | Actual | $ 467,553 | | |
| Historical | 2015 | Actual | $ 489,896 | | |
| Historical | 2016 | Actual | $ 488,319 | | |
| Bridge Year (Foreca | 2017 | Forecast | $ 482,915 | | |
| Test Year (Forecast | 2018 | Forecast | $ 494,817 | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | 2012 | | |
| | 2013 | 25.8% | |
| | 2014 | 22.9% | |
| | 2015 | 4.8% | |
| | 2016 | -0.3% | |
| | 2017 | -1.1% | |
| | 2018 | 2.5% | 20.5% |
| | Geometric Mean | 10.4% | 6.4% |

9 **Customer Class:** Standard A General - Air Access

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

| | Calendar Year (for 2017 Cost of Service | Customers | | | |
|---|---|---|---|---|---|
| Historical | 2012 | Actual | 292 | | |
| Historical | 2013 | Actual | 293 | Board-approved | 305 |
| Historical | 2014 | Actual | 290 | | |
| Historical | 2015 | Actual | 292 | | |
| Historical | 2016 | Actual | 285 | | |
| Bridge Year | 2017 | Forecast | 287 | | |
| Test Year | 2018 | Forecast | 288 | | |

| Consumption (kWh) [3] | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 9,130,800 | 9,130,800 | | |
| Actual | 9,224,362 | 9,224,362 | Board-approved | 9,460,635 |
| Actual | 9,842,743 | 9,842,743 | | |
| Actual | 9,174,261 | 9,174,261 | | |
| Actual | 9,904,451 | 9,904,451 | | |
| Forecast | 9,298,513 | 9,298,513 | | |
| Forecast | 9,408,294 | 9,408,294 | | |

| Consumption (kWh) per Customer | Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|
| Actual | 31,270 | 31,270 | | |
| Actual | 31,482 | 31,482 | Board-approved | 31,018 |
| Actual | 33,940 | 33,940 | | |
| Actual | 31,419 | 31,419 | | |
| Actual | 34,752 | 34,752 | | |
| Forecast | 32,399 | 32,399 | | |
| Forecast | 32,668 | 32,668 | | |

**Variance Analysis**

| Year | Customers Year-over-year | Customers Test Year Versus Board-approved | Consumption Year-over-year (Actual) | Consumption Year-over-year (Weather-normalized) | Consumption Test Year Versus Board-approved | Per Customer Year-over-year (Actual) | Per Customer Year-over-year (Weather-normalized) | Per Customer Test Year Versus Board-approved |
|---|---|---|---|---|---|---|---|---|
| 2012 | | | | | | | | |
| 2013 | 0.3% | | 1.0% | 1.0% | | 0.7% | 0.7% | |
| 2014 | -1.0% | | 6.7% | 6.7% | | 7.8% | 7.8% | |
| 2015 | 0.7% | | -6.8% | -6.8% | | -7.4% | -7.4% | |
| 2016 | -2.4% | | 8.0% | 8.0% | | 10.6% | 10.6% | |
| 2017 | 0.7% | | | -6.1% | | | -6.8% | |
| 2018 | 0.3% | -5.6% | | 1.2% | -0.6% | | 0.8% | 5.3% |
| Geometric Mean | -0.3% | -1.9% | 2.7% | 0.6% | -0.2% | 3.6% | 0.9% | 1.7% |

| | Calendar Year (for 2017 Cost of Service | Revenues | | | |
|---|---|---|---|---|---|
| Historical | 2012 | Actual | $ 7,895,150 | | |
| Historical | 2013 | Actual | $ 8,307,739 | Board-approved | $ 8,662,630 |
| Historical | 2014 | Actual | $ 9,301,908 | | |
| Historical | 2015 | Actual | $ 8,777,016 | | |
| Historical | 2016 | Actual | $ 9,597,680 | | |
| Bridge Year (Foreca | 2017 | Forecast | $ 9,187,720 | | |
| Test Year (Forecast | 2018 | Forecast | $ 9,502,376 | | |

| Variance Analysis Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|
| 2012 | | |
| 2013 | 5.2% | |
| 2014 | 12.0% | |
| 2015 | -5.6% | |
| 2016 | 9.4% | |
| 2017 | -4.3% | |
| 2018 | 3.4% | 9.7% |
| Geometric Mean | 3.8% | 3.1% |

**10 Customer Class:** | | Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

| | Calendar Year (for 2017 Cost of Service | Customers | | | | Consumption (kWh) [3] Actual (Weather actual) | Weather-normalized | | Weather-normalized | | Consumption (kWh) per Customer Actual (Weather actual) | Weather-normalized | | Weather-normalized |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Historical | *2012* | Actual | | | | Actual | | - | | | Actual | | | |
| Historical | *2013* | Actual | | Board-approved | | Actual | | - | Board-approved | 0 | Actual | | Board-approved | |
| Historical | *2014* | Actual | | | | Actual | | - | | | Actual | | | |
| Historical | *2015* | Actual | | | | Actual | | - | | | Actual | | | |
| Historical | *2016* | Actual | | | | Actual | | - | | | Actual | | | |
| Bridge Year | *2017* | Forecast | | | | Forecast | | - | | | Forecast | | | |
| Test Year | *2018* | Forecast | | | | Forecast | | - | | | Forecast | | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved | Year | Year-over-year | Test Year Versus Board-approved | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|---|---|---|---|---|---|
| | *2012* | | | *2012* | | | *2012* | | |
| | *2013* | | | *2013* | | | *2013* | | |
| | *2014* | | | *2014* | | | *2014* | | |
| | *2015* | | | *2015* | | | *2015* | | |
| | *2016* | | | *2016* | | | *2016* | | |
| | *2017* | | | *2017* | | | *2017* | | |
| | *2018* | | | *2018* | | | *2018* | | |
| | Geometric Mean | | | Geometric Mean | | | Geometric Mean | | |

| | Calendar Year (for 2017 Cost of Service | Revenues | | | |
|---|---|---|---|---|---|
| Historical | *2012* | Actual | | | |
| Historical | *2013* | Actual | | Board-approved | |
| Historical | *2014* | Actual | | | |
| Historical | *2015* | Actual | | | |
| Historical | *2016* | Actual | | | |
| Bridge Year (Foreca | *2017* | Forecast | | | |
| Test Year (Forecast | *2018* | Forecast | | | |

| Variance Analysis | Year | Year-over-year | Test Year Versus Board-approved |
|---|---|---|---|
| | *2012* | | |
| | *2013* | | |
| | *2014* | | |
| | *2015* | | |
| | *2016* | | |
| | *2017* | | |
| | *2018* | | |
| | Geometric Mean | | |

**Note:** If there are more than ten (10) customer classes, please contact OEB Staff to add tables for additional customer classes.

**Hydro One Remote Communities Inc.**
**Statistical Data for Load Forecast**
**Load Forecast by Month**

| SUMMARY | 2018 PROJECTED | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| **Residential - Year Round - Non Std. 'A'** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 2,684 | 2,685 | 2,687 | 2,689 | 2,691 | 2,693 | 2,695 | 2,697 | 2,699 | 2,701 | 2,702 | 2,704 | 2,684 |
| Customer Additions/Deletions | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 23 |
| Number of Customers - End of Period | 2,685 | 2,687 | 2,689 | 2,691 | 2,693 | 2,695 | 2,697 | 2,699 | 2,701 | 2,702 | 2,704 | 2,706 | 2,706 |
| Effective # of Customers During Period | 2,684 | 2,686 | 2,688 | 2,690 | 2,692 | 2,694 | 2,696 | 2,698 | 2,700 | 2,701 | 2,703 | 2,705 | 2,695 |
| Average kWh's/Customer Previous Year | 1,544 | 1,537 | 1,538 | 1,241 | 1,244 | 1,246 | 884 | 884 | 884 | 1,133 | 1,131 | 1,130 | 14,392 |
| kWh's/Customer Increases/Decreases | 6 | 6 | 6 | 5 | 5 | 5 | 3 | 3 | 3 | 4 | 4 | 5 | 55 |
| Average kWh's/Customer During Period | 1,549 | 1,543 | 1,544 | 1,246 | 1,249 | 1,251 | 887 | 887 | 887 | 1,137 | 1,136 | 1,136 | 14,447 |
| | 4,159,392 | 4,144,363 | 4,150,140 | 3,351,888 | 3,361,130 | 3,370,349 | 2,392,183 | 2,393,817 | 2,395,451 | 3,072,553 | 3,070,133 | 3,073,824 | 38,935,222 |
| Total kWh's for Period | | | | | | | | | | | | | |
| **Residential - Seasonal** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 146 | 146 | 146 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 146 |
| Customer Additions/Deletions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Number of Customers - End of Period | 146 | 146 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 147 |
| Effective # of Customers During Period | 146 | 146 | 146 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 147 |
| Average kWh's/Customer Previous Year | 180 | 180 | 180 | 88 | 88 | 87 | 197 | 197 | 197 | 242 | 243 | 244 | 2,123 |
| kWh's/Customer Increases/Decreases | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 8 |
| Average kWh's/Customer During Period | 181 | 181 | 181 | 88 | 88 | 87 | 198 | 198 | 198 | 243 | 244 | 245 | 2,125 |
| | 26,511 | 26,516 | 26,443 | 12,932 | 12,905 | 12,782 | 28,978 | 28,985 | 29,017 | 35,572 | 35,765 | 35,999 | 312,406 |
| Total kWh's for Period | | | | | | | | | | | | | |
| **General Service 1-Phase - Non Std. 'A'** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 303 | 303 | 304 | 304 | 305 | 305 | 306 | 306 | 306 | 307 | 307 | 308 | 303 |
| Customer Additions/Deletions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 |
| Number of Customers - End of Period | 303 | 304 | 304 | 305 | 305 | 306 | 306 | 306 | 307 | 307 | 308 | 308 | 308 |
| Effective # of Customers During Period | 303 | 304 | 304 | 304 | 305 | 305 | 306 | 306 | 307 | 307 | 307 | 308 | 306 |
| Average kWh's/Customer Previous Year | 2,277 | 2,277 | 2,238 | 1,724 | 1,724 | 1,728 | 1,345 | 1,394 | 1,394 | 1,618 | 1,617 | 1,616 | 20,938 |
| kWh's/Customer Increases/Decreases | 11 | 11 | 11 | 9 | 9 | 9 | 7 | 7 | 7 | 8 | 8 | 8 | 68 |
| Average kWh's/Customer During Period | 2,289 | 2,288 | 2,249 | 1,733 | 1,733 | 1,736 | 1,352 | 1,401 | 1,401 | 1,626 | 1,626 | 1,625 | 21,006 |
| | 693,907 | 694,767 | 683,885 | 527,572 | 528,208 | 530,052 | 413,286 | 428,942 | 429,479 | 499,018 | 499,647 | 499,083 | 6,427,846 |
| Total kWh's for Period **General Service 3-Phase - Non Std. 'A'** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 |
| Customer Additions/Deletions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| Number of Customers - End of Period | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 44 | 44 |
| Effective # of Customers During Period | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 44 | 43 |
| Average kWh's/Customer Previous Year | 11,673 | 11,671 | 11,418 | 9,102 | 8,973 | 8,971 | 8,755 | 8,751 | 8,748 | 9,426 | 9,425 | 9,423 | 116,296 |
| kWh's/Customer Increases/Decreases | 53 | 53 | 52 | 42 | 42 | 42 | 41 | 41 | 41 | 44 | 44 | 44 | 960 |
| Average kWh's/Customer During Period | 11,726 | 11,725 | 11,470 | 9,144 | 9,015 | 9,012 | 8,796 | 8,792 | 8,788 | 9,470 | 9,468 | 9,467 | 117,256 |
| | 503,254 | 503,837 | 493,525 | 392,750 | 387,690 | 387,489 | 379,206 | 379,540 | 379,874 | 411,152 | 411,610 | 412,077 | 5,042,005 |
| Total kWh's for Period **Street Lighting** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 7 |
| Customer Additions/Deletions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Number of Customers - End of Period | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Effective # of Customers During Period | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Average kWh's/Customer Previous Year | 3,202 | 3,189 | 3,177 | 3,164 | 3,152 | 3,140 | 3,128 | 3,116 | 3,104 | 3,092 | 3,080 | 2,215 | 36,732 |
| kWh's/Customer Increases/Decreases | (149) | (148) | (148) | (147) | (147) | (146) | (145) | (45) | (144) | (144) | (143) | (103) | (3,826) |
| Average kWh's/Customer During Period | 3,053 | 3,041 | 3,029 | 3,017 | 3,005 | 2,994 | 2,982 | 3,071 | 2,959 | 2,948 | 2,937 | 2,112 | 32,906 |

| SUMMARY | 2018 PROJECTED | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| | 22,513 | 22,510 | 22,506 | 22,503 | 22,499 | 22,495 | 22,490 | 22,075 | 22,482 | 22,478 | 22,474 | 16,221 | 263,245 |
| Total kWh's for Period | | | | | | | | | | | | | |
| **Residential - Road Access - Std. 'A'** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Customer Additions/Deletions | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Number of Customers - End of Period | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Effective # of Customers During Period | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Average kWh's/Customer Previous Year | 775 | 775 | 811 | 325 | 325 | 325 | 369 | 369 | 369 | 501 | 501 | 501 | 5,944 |
| kWh's/Customer Increases/Decreases | 4 | 4 | 4 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 28 |
| Average kWh's/Customer During Period | 778 | 778 | 815 | 327 | 327 | 327 | 370 | 370 | 370 | 503 | 503 | 503 | 5,971 |
| | 6,225 | 6,225 | 6,519 | 2,612 | 2,612 | 2,612 | 2,963 | 2,963 | 2,963 | 4,024 | 4,024 | 4,026 | 47,771 |
| Total kWh's for Period | | | | | | | | | | | | | |
| **Residential - Air Access - Std. 'A"** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 132 | 132 | 132 | 133 | 133 | 133 | 133 | 134 | 134 | 134 | 134 | 135 | 132 |
| Customer Additions/Deletions | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 6 |
| Number of Customers - End of Period | 132 | 133 | 133 | 133 | 133 | 134 | 134 | 134 | 134 | 135 | 135 | 135 | 138 |
| Effective # of Customers During Period | 132 | 132 | 133 | 133 | 133 | 133 | 134 | 134 | 134 | 134 | 135 | 135 | 135 |
| Average kWh's/Customer Previous Year | 1,156 | 1,155 | 1,149 | 923 | 920 | 920 | 591 | 591 | 591 | 886 | 874 | 833 | 10,567 |
| kWh's/Customer Increases/Decreases | (5) | (5) | (5) | (4) | (4) | (4) | (1) | (3) | (3) | (4) | (4) | 96 | (56) |
| Average kWh's/Customer During Period | 1,151 | 1,149 | 1,143 | 919 | 916 | 916 | 590 | 588 | 588 | 882 | 870 | 929 | 10,510 |
| | 151,924 | 152,043 | 151,506 | 122,053 | 121,879 | 122,067 | 78,879 | 78,727 | 78,842 | 118,499 | 117,128 | 125,342 | 1,418,887 |
| Total kWh's for Period | | | | | | | | | | | | | |
| **General Service - Road Access - Std. 'A'** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| Customer Additions/Deletions | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Number of Customers - End of Period | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| Effective # of Customers During Period | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| Average kWh's/Customer Previous Year | 3,203 | 3,203 | 3,567 | 2,500 | 2,500 | 2,500 | 2,188 | 2,188 | 2,188 | 2,693 | 2,693 | 2,693 | 32,117 |
| kWh's/Customer Increases/Decreases | 16 | 16 | 18 | 13 | 13 | 13 | 11 | 11 | 11 | 14 | 14 | 15 | 166 |
| Average kWh's/Customer During Period | 3,219 | 3,219 | 3,585 | 2,513 | 2,513 | 2,513 | 2,199 | 2,199 | 2,199 | 2,707 | 2,707 | 2,708 | 32,283 |
| | 70,825 | 70,825 | 78,868 | 55,291 | 55,291 | 55,291 | 48,382 | 48,382 | 48,382 | 59,557 | 59,557 | 59,576 | 710,230 |

Total kWh's for Period

| SUMMARY | 2018 PROJECTED | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| | | | | | | | | | | | | | |
| **General Service - Air Access - Std. 'A'** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 287 | 287 | 287 | 287 | 287 | 287 | 288 | 288 | 288 | 288 | 288 | 288 | 287 |
| Customer Additions/Deletions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Number of Customers - End of Period | 287 | 287 | 287 | 287 | 288 | 288 | 288 | 288 | 288 | 288 | 288 | 288 | 289 |
| Effective # of Customers During Period | 287 | 287 | 287 | 287 | 287 | 288 | 288 | 288 | 288 | 288 | 288 | 288 | 288 |
| Average kWh's/Customer Previous Year | 3,384 | 3,384 | 3,311 | 2,857 | 2,857 | 2,865 | 2,022 | 2,023 | 2,023 | 2,588 | 2,588 | 2,588 | 32,484 |
| kWh's/Customer Increases/Decreases | 20 | 20 | 20 | 17 | 17 | 17 | 12 | 12 | 12 | 15 | 15 | 56 | 184 |
| Average kWh's/Customer During Period | 3,404 | 3,404 | 3,331 | 2,874 | 2,874 | 2,882 | 2,034 | 2,035 | 2,035 | 2,603 | 2,603 | 2,644 | 32,668 |
| | 977,399 | 977,747 | 956,953 | 825,835 | 826,132 | 828,628 | 585,043 | 585,273 | 585,502 | 749,070 | 749,326 | 761,388 | 9,408,294 |
| Total kWh's for Period | | | | | | | | | | | | | |
| **TOTAL SUMMARY** | | | | | | | | | | | | | |
| Number of Customers Start of Period | 3,632 | 3,635 | 3,637 | 3,640 | 3,643 | 3,646 | 3,648 | 3,651 | 3,654 | 3,657 | 3,659 | 3,662 | 3,632 |
| Customer Additions/Deletions | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 37 |
| Number of Customers - End of Period | 3,635 | 3,638 | 3,641 | 3,643 | 3,646 | 3,649 | 3,652 | 3,654 | 3,657 | 3,660 | 3,663 | 3,665 | 3,669 |
| Effective # of Customers During Period | 3,634 | 3,636 | 3,639 | 3,642 | 3,645 | 3,647 | 3,650 | 3,653 | 3,656 | 3,658 | 3,661 | 3,664 | 3,652 |
| Average kWh's/Customer Previous Year | 1,802 | 1,797 | 1,788 | 1,446 | 1,446 | 1,449 | 1,072 | 1,076 | 1,076 | 1,346 | 1,345 | 1,340 | 16,975 |
| kWh's/Customer Increases/Decreases | 18 | 18 | 18 | 14 | 13 | 13 | 10 | 11 | 11 | 13 | 13 | 21 | 155 |
| Average kWh's/Customer During Period | 1,820 | 1,815 | 1,806 | 1,459 | 1,459 | 1,462 | 1,083 | 1,086 | 1,087 | 1,359 | 1,357 | 1,361 | 17,130 |
| | 6,611,949 | 6,598,832 | 6,570,346 | 5,313,436 | 5,318,348 | 5,331,765 | 3,951,410 | 3,968,704 | 3,971,993 | 4,971,923 | 4,969,665 | 4,987,533 | 62,565,904 |

Total kWh's for Period

# Hydro One Remote Communities Inc.
# Load Forecast versus Actual

**Analysis of Load Forecast variance, and information demonstrating accuracy of past load forecasts.**

## Off- Grid Communities

| Year | KWH SOLD Forecast | KWH SOLD Actual | % Variance |
|---|---|---|---|
| 2012 | 55,805,691 | 56,124,200 | 0.6% |
| 2013 | 59,313,977 | 58,628,424 | -1.2% |
| 2014 | 59,178,450 | 62,338,648 | 5.3% |
| 2015 | 64,863,985 | 61,100,418 | -5.8% |
| 2016 | 64,702,850 | 64,439,719 | -0.4% |
| June 2017 | 35,087,085 | 33,590,931 | -4.3% |

## Grid Communities

| Year | KWH SOLD Forecast | KWH SOLD Actual | % Variance |
|---|---|---|---|
| 2012 | - | - | 0.0% |
| 2013 | 12,862,712 | - | -100.0% |
| 2014 | 1,920,873 | - | -100.0% |
| 2015 | 1,920,873 | - | -100.0% |
| 2016 | 1,920,873 | - | -100.0% |
| June 2017 | - | - | |

Cat Lake and Pikangikum did not join Remotes' service territory as expected in 2013

## Total

| Year | KWH SOLD Forecast | KWH SOLD Actual | % Variance |
|---|---|---|---|
| 2012 | 55,805,691 | 56,124,200 | 0.6% |
| 2013 | 72,176,689 | 58,628,424 | -18.8% |
| 2014 | 61,099,323 | 62,338,648 | 2.0% |
| 2015 | 66,784,858 | 61,100,418 | -8.5% |
| 2016 | 66,623,723 | 64,439,719 | -3.3% |
| June 2017 | 35,087,085 | 33,590,931 | -4.3% |

## Appendix 2-H
## Other Operating Revenue

| | USoA Description | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|---|
| | | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| | *Reporting Basis* | | | | | | |
| | Specific Service Charges | (42,168) | (33,224) | (726,045) | (258,902) | (641,100) | (291,600) |
| | Late Payment Charges | (299,633) | (93,678) | (303,546) | (382,973) | (300,000) | (318,000) |
| | Remote Rate Protection | (34,245,170) | (34,851,970) | (30,440,501) | (31,143,389) | (36,559,000) | (38,078,000) |
| | Rev from Merchandise and Jobbing | (462,535) | (366,920) | (578,820) | (912,880) | (389,000) | (389,000) |
| | Costs & Exp of Merchandise and Jobbing | 206,254 | 172,048 | 265,315 | 341,894 | 135,000 | 135,000 |
| | Revenues from Non-Ut | (13,010) | (12,925) | (13,531) | (14,376) | (11,000) | (17,000) |
| | | | | | | | |
| Specific Service Charges | | (42,168) | (33,224) | (726,045) | (258,902) | (641,100) | (291,600) |
| Late Payment Charges | | (299,633) | (93,678) | (303,546) | (382,973) | (300,000) | (318,000) |
| Other Operating Revenues | | (34,245,170) | (34,851,970) | (30,440,501) | (31,143,389) | (36,559,000) | (38,078,000) |
| Other Income or Deductions | | (269,291) | (207,797) | (327,036) | (585,362) | (265,000) | (271,000) |
| Total | | (34,856,262) | (35,186,669) | (31,797,128) | (32,370,626) | (37,765,100) | (38,958,600) |

| Description | Account(s) |
|---|---|
| Specific Service Charges: | **4235** — **red bold** font have activity |
| Late Payment Charges: | **4225** |
| Other Distribution Revenues: | 4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, **4245** |
| Other Income and Expenses: | 4305, 4310, 4315, 4320, **4325, 4330,** 4335, 4340, 4345, 4350, **4355,** 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415 |

**Note: Add all applicable accounts listed above to the table and include all relevant information.**

**Account Breakdown Details**

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

**Account - Interest and Dividend Income**

| | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| Reporting Basis | | | | | | |
| Short-term Investment Interest | | | | | | |
| Bank Deposit Interest | | | | | | |
| Miscellaneous Interest Revenue | | | | | | |
| etc.[1] | | | | | | |
| | | | | | | |
| Total | $ - | $ - | $ - | $ - | $ - | $ - |

**Notes:**

1 List and specify any other interest revenue.

2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1, 2015, 2014 must be presented in both a CGAAP and MIFRS basis.

3 Remotes does not earn interest or divident income

**Account - Specific Service Charges**

| | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| Reporting Basis | | | | | | |
| Account Set up fee/Disconnection/Reconnection fee | -$ 13,464 | -$ 10,380 | -$ 13,708 | -$ 10,614 | -$ 12,000 | -$ 12,000 |
| Miscellaneous Distribtution (work order close) | -$ 28,704 | -$ 22,844 | -$ 64,918 | -$ 19,322 | -$ 26,000 | -$ 26,000 |
| Miscellaneous Generation (work order close) | $ - | $ - | -$ 647,419 | -$ 228,966 | -$ 603,100 | -$ 253,600 |
| Total | -$ 42,168 | -$ 33,224 | -$ 726,045 | -$ 258,902 | -$ 641,100 | -$ 291,600 |

**Account - Late Payment Charges**

| | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| Reporting Basis | | | | | | |
| Late Payment Charges (Energy) | -$ 290,826 | -$ 91,024 | -$ 297,170 | -$ 362,830 | -$ 294,000 | -$ 312,000 |
| Late Payment Charges (non-Energy) | -$ 8,807 | -$ 2,654 | -$ 6,377 | -$ 20,142 | -$ 6,000 | -$ 6,000 |
| Total | -$ 299,633 | -$ 93,678 | -$ 303,546 | -$ 382,973 | -$ 300,000 | -$ 318,000 |

**Account - Remote Rate Protection**

| | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| Reporting Basis | | | | | | |
| Remote Rate Protection | -$ 33,046,000 | -$ 32,259,000 | -$ 32,259,000 | -$ 32,259,000 | -$ 36,559,000 | -$ 38,078,000 |
| Remote Rate Protection Variance | -$ 1,199,170 | -$ 2,592,970 | $ 1,818,499 | $ 1,115,611 | $ - | $ - |
| Total | -$ 34,245,170 | -$ 34,851,970 | -$ 30,440,501 | -$ 31,143,389 | -$ 36,559,000 | -$ 38,078,000 |

**Account - Rev from Merchandise and Jobbing**

| | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| Reporting Basis | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| CIA and Engineering Design | $ - | -$ 28,571 | -$ 43,405 | -$ 83,338 | $ - | $ - |
| Street Lighting | -$ 39,396 | -$ 40,423 | $ - | -$ 75,094 | -$ 10,000 | -$ 10,000 |
| Intercompany Services | -$ 195,358 | -$ 109,500 | -$ 212,671 | -$ 468,903 | -$ 212,000 | -$ 212,000 |
| Community Assessments | $ - | $ - | -$ 11,967 | -$ 93,051 | $ - | $ - |
| Support for ESA and Other | -$ 227,781 | -$ 188,426 | -$ 310,777 | -$ 192,494 | -$ 167,000 | -$ 167,000 |
| | | | | | | |
| **Total** | -$ 462,535 | -$ 366,920 | -$ 578,820 | -$ 912,880 | -$ 389,000 | -$ 389,000 |

**Account - Costs & Exp of Merchandise and Jobbing**

| | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Reporting Basis** | | | | | | |
| CIA and Engineering Design | $ - | $ 5,149 | -$ 5,149 | $ 67,727 | $ - | $ - |
| Street Lighting | $ 37,547 | $ 38,399 | $ - | $ 69,627 | $ 9,000 | $ 9,000 |
| Community Assessments | $ - | $ - | $ 11,117 | $ 67,933 | $ - | $ - |
| Support for ESA and Other | $ 168,707 | $ 128,500 | $ 259,347 | $ 136,607 | $ 126,000 | $ 126,000 |
| **Total** | $ 206,254 | $ 172,048 | $ 265,315 | $ 341,894 | $ 135,000 | $ 135,000 |

**Account - Revenue from Non-Ut**

| | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Reporting Basis** | | | | | | |
| OCI | -$ 13,010 | -$ 12,925 | -$ 13,531 | -$ 14,376 | -$ 11,000 | -$ 17,000 |
| **Total** | -$ 13,010 | -$ 12,925 | -$ 13,531 | -$ 14,376 | -$ 11,000 | -$ 17,000 |

**Effective Rates**
**Revenue Reconciliation**

| Residential - Year Round - Non Std. 'A' | # Customers | Estimated kWh | Rate | Revenue |
|---|---|---|---|---|
| Monthly Service Charge | 2,695 | | 19.68 | 636,412 |
| Electricity Charges - 1st 1,000 kWh | | 26,831,785 | 0.0926 | 2,484,623 |
| Electricity Charges - Next 1,500 kWh | | 10,645,490 | 0.1236 | 1,315,783 |
| Electricity Charges - All Additional kWh | | 1,457,947 | 0.1862 | 271,470 |
| **Total** | | **38,935,222** | | **4,708,287** |
| **Residential - Seasonal** | | | | |
| Monthly Service Charge | 147 | | 33.26 | 58,504 |
| Electricity Charges - 1st 1,000 kWh | | 312,406 | 0.0926 | 28,929 |
| Electricity Charges - Next 1,500 kWh | | - | 0.1236 | - |
| Electricity Charges - All Additional kWh | | - | 0.1862 | - |
| **Total** | | **312,406** | | **87,433** |
| **General Service 1-Phase - Non Std. 'A'** | | | | |
| Monthly Service Charge | 306 | | 33.46 | 122,664 |
| Electricity Charges - 1st 6,000 kWh | | 5,930,738 | 0.1038 | 615,611 |
| Electricity Charges - Next 7,000 kWh | | 409,062 | 0.1377 | 56,328 |
| Electricity Charges - All Additional kWh | | 88,046 | 0.1862 | 16,394 |
| **Total** | | **6,427,846** | | **810,997** |
| **General Service 3-Phase - Non Std. 'A'** | | | | |
| Monthly Service Charge | 43 | | 41.89 | 21,699 |
| Electricity Charges - 1st 25,000 kWh | | 4,827,342 | 0.1038 | 501,078 |
| Electricity Charges - Next 15,000 kWh | | 198,166 | 0.1377 | 27,287 |
| Electricity Charges - All Additional kWh | | 16,497 | 0.1862 | 3,072 |
| **Total** | | **5,042,005** | | **553,136** |
| **Street Lighting** | | | | |
| | 8 | | - | |
| Electricity Charges | | 263,245 | 0.1029 | 27,088 |
| | | | | |
| | | | | |
| **Total** | | **263,245** | | **27,088** |
| **Residential - Road Access - Std. 'A'** | | | | |
| Electricity Charges - 1st 250 kWh | 8 | 22,623 | 0.6097 | 13,793 |
| Electricity Charges - All Additional kWh | | 25,148 | 0.6967 | 17,520 |
| | | | | |
| | | | | |
| **Total** | | **47,771** | | **31,314** |
| **General Service - Road Access - Std. 'A'** | | | | |
| | 22 | | | |
| Electricity Charges | | 710,230 | 0.6967 | 494,817 |
| | | | | |
| | | | | |
| **Total** | | **710,230** | | **494,817** |
| **Residential - Air Access - Std. 'A"** | | | | |
| Electricity Charges - 1st 250 kWh | 135 | 404,750 | 0.9205 | 372,572 |
| Electricity Charges - All Additional kWh | | 1,014,137 | 1.0100 | 1,024,278 |
| | | | | |
| | | | | |
| **Total** | | **1,418,887** | | **1,396,850** |
| **General Service - Air Access - Std. 'A'** | | | | |
| | 288 | | | |
| Electricity Charges | | 9,408,294 | 1.0100 | 9,502,376 |
| | | | | |
| | | | | |
| **Total** | | **9,408,294** | | **9,502,376** |
| **Summary** | **3,652** | **62,565,904** | | **17,612,299** |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2016-0083

## NON STANDARD A YEAR ROUND RESIDENTIAL SERVICE CLASSIFICATION – R2

This classification refers to a residential service that is the principal residence of the customer. This classification may include additional buildings served through the same meter, provided they are not rental income units. To be classed as year round residential, all of the following criteria must be met:

- Occupants must state that this is their principal residence for purposes of the Income Tax Act;
- The occupant must live in this residence for at least 8 months of the year;
- The address of this residence must appear on the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.;
- Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Service Charge | $ | 19.45 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0915 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1221 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

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EB-2016-0083

## NON STANDARD A SEASONAL RESIDENTIAL SERVICE CLASSIFICATION – R4

This classification is comprised of any residential service not meeting the year-round residential criteria. As such, the seasonal residential class includes cottages, chalets, and camps. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Service Charge | $ | 32.87 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0915 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1221 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

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EB-2016-0083

## NON STANDARD A GENERAL SERVICE SINGLE PHASE SERVICE CLASSIFICATION – G1

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Single Phase customers. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Service Charge | $ | 33.06 |
| Electricity Rate - First 6,000 kWh | $/kWh | 0.1026 |
| Electricity Rate - Next 7,000 kWh | $/kWh | 0.1361 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2016-0083

## NON STANDARD A GENERAL SERVICE THREE PHASE SERVICE CLASSIFICATION – G3

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Three Phase customers. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Service Charge | $ | 41.39 |
| Electricity Rate - First 25,000 kWh | $/kWh | 0.1026 |
| Electricity Rate - Next 15,000 kWh | $/kWh | 0.1361 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2016-0083

## STREET LIGHTING SERVICE CLASSIFICATION

The energy consumption for street lights is estimated based on Remotes' profile for street lighting load, which provides the amount of time each month that the street lights are operating. Streetlight charges include:

- An energy charge based on installed load, at a rate approved annually (Dollars per kWh x # of fixtures x billing);
- A pole rental charge approved annually, when the light is attached to a Remotes' pole.

Remotes must approve the location of new lighting installations on its poles and the streetlight owner must enter into an agreement to use such poles. Remotes will make the electrical service connection of all streetlights to the distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate | \$/kWh | 0.1017 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2016-0083

## STANDARD A RESIDENTIAL ROAD/RAIL ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Aboriginal Affairs and Northern Development Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate - First 250 kWh | \$/kWh | 0.6025 |
| Electricity Rate - All Additional kWh | \$/kWh | 0.6884 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2016-0083

## STANDARD A RESIDENTIAL AIR ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are not accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate - First 250 kWh | $/kWh | 0.9096 |
| Electricity Rate - All Additional kWh | $/kWh | 0.9955 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2016-0083

## STANDARD A GENERAL SERVICE ROAD/RAIL ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor’s Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.6884 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2016-0083

## STANDARD A GENERAL SERVICE AIR ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are not accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.9955 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2016-0083

## microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# Hydro One Remote Communities Inc.
## Current Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2016-0083

# STANDARD A GRID CONNECTED SERVICE CLASSIFICATION

This classification is applicable to all Standard A customers in communities that are connected to the grid and are not accessible by a year-round road or by rail.

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

## MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate | \$/kWh | 0.3119 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

# SPECIFIC SERVICE CHARGES

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

| | | |
|---|---|---|
| Customer Administration | | |
| Arrears Certificate | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Returned Cheque (plus bank charges) | $ | 15.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |
| Non-Payment of Account | | |
| Late Payment - per month | % | 1.50 |
| Late Payment - per annum | % | 19.56 |
| Collection/Disconnection/Load Limiter/Reconnection – if in Community | $ | 65.00 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## NON STANDARD A YEAR ROUND RESIDENTIAL SERVICE CLASSIFICATION – R2

This classification refers to a residential service that is the principal residence of the customer. This classification may include additional buildings served through the same meter, provided they are not rental income units. To be classed as year round residential, all of the following criteria must be met:

- Occupants must state that this is their principal residence for purposes of the Income Tax Act;
- The occupant must live in this residence for at least 8 months of the year;
- The address of this residence must appear on the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.;
- Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Service Charge | $ | 19.80 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0931 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1243 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## NON STANDARD A SEASONAL RESIDENTIAL SERVICE CLASSIFICATION – R4

This classification is comprised of any residential service not meeting the year-round residential criteria. As such, the seasonal residential class includes cottages, chalets, and camps. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Service Charge | $ | 33.46 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0931 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1243 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## NON STANDARD A GENERAL SERVICE SINGLE PHASE SERVICE CLASSIFICATION – G1

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Single Phase customers. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Service Charge | $ | 33.66 |
| Electricity Rate - First 6,000 kWh | $/kWh | 0.1044 |
| Electricity Rate - Next 7,000 kWh | $/kWh | 0.1385 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## NON STANDARD A GENERAL SERVICE THREE PHASE SERVICE CLASSIFICATION – G3

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Three Phase customers. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Service Charge | $ | 42.14 |
| Electricity Rate - First 25,000 kWh | $/kWh | 0.1044 |
| Electricity Rate - Next 15,000 kWh | $/kWh | 0.1385 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## STREET LIGHTING SERVICE CLASSIFICATION

The energy consumption for street lights is estimated based on Remotes' profile for street lighting load, which provides the amount of time each month that the street lights are operating. Streetlight charges include:

- An energy charge based on installed load, at a rate approved annually (Dollars per kWh x # of fixtures x billing);
- A pole rental charge approved annually, when the light is attached to a Remotes' pole.

Remotes must approve the location of new lighting installations on its poles and the streetlight owner must enter into an agreement to use such poles. Remotes will make the electrical service connection of all streetlights to the distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.1035 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## STANDARD A RESIDENTIAL ROAD/RAIL ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Aboriginal Affairs and Northern Development Canada. Further servicing details are available in the distributor’s Conditions of Service.

This classification is applicable to residential customers in communities that are accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate - First 250 kWh | $/kWh | 0.6133 |
| Electricity Rate - All Additional kWh | $/kWh | 0.7008 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## STANDARD A RESIDENTIAL AIR ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are not accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate - First 250 kWh | $/kWh | 0.9260 |
| Electricity Rate - All Additional kWh | $/kWh | 1.0134 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## STANDARD A GENERAL SERVICE ROAD/RAIL ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.7008 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## STANDARD A GENERAL SERVICE AIR ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are not accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 1.0134 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# Hydro One Remote Communities Inc.
# Proposed Remote Communities Rate Schedule
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2017-0051

## STANDARD A GRID CONNECTED SERVICE CLASSIFICATION

This classification is applicable to all Standard A customers in communities that are connected to the grid and are not accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.3175 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

| | | |
|---|---|---|
| Customer Administration | | |
| Arrears Certificate | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Returned Cheque (plus bank charges) | $ | 15.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |
| Non-Payment of Account | | |
| Late Payment - per month | % | 1.50 |
| Late Payment - per annum | % | 19.56 |
| Collection/Disconnection/Load Limiter/Reconnection – if in Community | $ | 65.00 |

# Hydro One Remote Communities Inc.
# Prorated Rate and Bills for 2018

| Rate Description | Metric | 2017 Approved Rates | 2018 Proposed Rates | Rate in Effect 4/12 of Year | Rate in Effect 8/12 of Year | Effective Rate for All of 2018 |
|---|---|---|---|---|---|---|
| | | | | Impact of 2018 Change | | |
| | | | | 33% | 67% | 100% |
| **Year-Round Residential – R2** | | | | | | |
| Service Charge | $ | 19.45 | 19.8 | 6.48 | 13.20 | 19.68 |
| **kWh Charges** | | | | | | |
| First 1,000 | $/kWh | 0.0915 | 0.0931 | 0.0305 | 0.0621 | 0.0926 |
| Next 1,500 kWh | $/kWh | 0.1221 | 0.1243 | 0.0407 | 0.0829 | 0.1236 |
| All Additional kWh | $/kWh | 0.1840 | 0.1873 | 0.0613 | 0.1249 | 0.1862 |
| **Seasonal Residential – R4** | | | | | | |
| Service Charge | $ | 32.87 | 33.46 | 10.96 | 22.31 | 33.26 |
| **kWh Charges** | | | | | | |
| First 1,000 | $/kWh | 0.0915 | 0.0931 | 0.0305 | 0.0621 | 0.0926 |
| Next 1,500 kWh | $/kWh | 0.1221 | 0.1243 | 0.0407 | 0.0829 | 0.1236 |
| All Additional kWh | $/kWh | 0.1840 | 0.1873 | 0.0613 | 0.1249 | 0.1862 |
| **General Service Single Phase – G1** | | | | | | |
| Service Charge | $ | 33.06 | 33.66 | 11.02 | 22.44 | 33.46 |
| **kWh Charges** | | | | | | |
| First 6,000 | $/kWh | 0.1026 | 0.1044 | 0.0342 | 0.0696 | 0.1038 |
| Next 7,000 kWh | $/kWh | 0.1361 | 0.1385 | 0.0454 | 0.0923 | 0.1377 |
| All Additional kWh | $/kWh | 0.1840 | 0.1873 | 0.0613 | 0.1249 | 0.1862 |
| Regulatory Charge | | | | | | |
| **General Service Three Phase – G3** | | | | | | |
| Service Charge | $ | 41.39 | 42.14 | 13.80 | 28.09 | 41.89 |
| **kWh Charges** | | | | | | |
| First 25,000 | $/kWh | 0.1026 | 0.1044 | 0.0342 | 0.0696 | 0.1038 |
| \ Next 15,000 kWh | $/kWh | 0.1361 | 0.1385 | 0.0454 | 0.0923 | 0.1377 |
| Energy Charge All Additional kWh | $/kWh | 0.1840 | 0.1873 | 0.0613 | 0.1249 | 0.1862 |
| Regulatory Charge | | | | | | |

| Rate Description | Metric | 2017 Approved Rates | 2018 Proposed Rates | Rate in Effect 4/12 of Year<br>Impact of 2018 Change<br>33% | Rate in Effect 8/12 of Year<br><br>67% | Effective Rate for All of 2018<br><br>100% |
|---|---|---|---|---|---|---|
| **Street Lighting** | | | | | | |
| **kWh Charges** | $/kWh | 0.1017 | 0.1035 | 0.0339 | 0.0690 | 0.1029 |
| **Standard A Residential Road/Rail** | | | | | | |
| **kWh Charges** | | | | | | |
| First 250 | $/kWh | 0.6025 | 0.6133 | 0.2008 | 0.4089 | 0.6097 |
| All Additional kWh | $/kWh | 0.6884 | 0.7008 | 0.2295 | 0.4672 | 0.6967 |
| **Standard A Residential Air Access** | | | | | | |
| Distribution Volumetric Rate | $/kWh | 0.9096 | 0.9260 | 0.3032 | 0.6173 | 0.9205 |
| **kWh Charges** | | | | | | |
| First 250 | $/kWh | 0.9955 | 1.0134 | 0.3318 | 0.6756 | 1.0074 |
| **Standard A General Service Road/Rail** | | | | | | |
| **kWh Charges** | $/kWh | 0.6884 | 0.7008 | 0.2295 | 0.4672 | 0.6967 |
| **Standard A General Service Air Access** | | | | | | |
| **kWh Charges** | $/kWh | 0.9955 | 1.0134 | 0.3318 | 0.6756 | 1.0074 |
| **Standard A Grid-Connected Air Access** | | | | | | |
| **kWh Charges** | $/kWh | 0.3119 | 0.3175 | 0.1040 | 0.2117 | 0.3156 |

## Rates Generator Model

| | |
|---|---|
| **Utility Name** | Hydro One Remote Communities Inc. |
| **Service Territory** | *Hydro One Remote Communities Inc.* |
| **Assigned EB Number** | EB-2016-0083 |
| **Name of Contact and Title** | Eryn MacKinnon |
| **Phone Number** | 416-345-4479 |
| **Email Address** | regulatory@HydroOne.com |
| **We are applying for rates effective** | Monday, May 01, 2017 |
| **Rate-Setting Method** | **Price Cap IR** |
| **Please indicate in which Rate Year the Group 1 accounts were last cleared** | **2013** |

**Notes**

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, including the MicroFit Class.

Effective Date, May 1, 2015

How many classes are listed on your most recent Board-Approved Tariff of Rates and Charges? 11

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

| | Rate Class Classification | |
|---|---|---|
| 1 | YEAR-ROUND RESIDENTIAL - R2 | |
| 2 | SEASONAL RESIDENTIAL - NORMAL DENSITY [R4] | |
| 3 | GENERAL SERVICE SINGLE PHASE - G1 | |
| 4 | GENERAL SERVICE THREE PHASE - G3 | 0 |
| 5 | STREET LIGHTING | |
| 6 | STANDARD A RESIDENTIAL ROAD/RAIL | |
| 7 | STANDARD A RESIDENTIAL AIR ACCESS | |
| 8 | STANDARD A GENERAL SERVICE ROAD/RAIL | |
| 9 | STANDARD A GENERAL SERVICE AIR ACCESS | |
| 10 | STANDARD A GRID CONNECTED SERVICE | |
| 11 | microFIT | |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
## Effective Date, May 1, 2017

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

| | UNIT | RATE |
|---|---|---|
| **Customer Administration** | | |
| Arrears certificate | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential) | $ | 30.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |
| **Non-Payment of Account** | | |
| Late Payment – per month | % | 1.50 |
| Late Payment – per annum | % | 19.56 |
| Collection/Disconnection/Load Limiter/Reconnection – if in Community | $ | 65.00 |

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

### Effective Date, May 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

## NON STANDARD A YEAR-ROUND RESIDENTIAL - R2

This classification refers to a residential service that is the principal residence of the customer. This classification may include additional buildings served through the same meter, provided they are not rental income units. To be classed as year round residential, all of the following criteria must be met:

- Occupants must state that this is their principal residence for purposes of the Income Tax Act;
- The occupant must live in this residence for at least 8 months of the year;
- The address of this residence must appear on the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.;
- Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Service Charge | $ | 19.45 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0915 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1221 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
### Effective Date, May 1, 2017

## SEASONAL RESIDENTIAL - NORMAL DENSITY [R4] Service Classification

This classification is comprised of any residential service not meeting the year-round residential criteria. As such, the seasonal residential class includes cottages, chalets, and camps. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES**

| | | |
|---|---|---|
| Service Charge | $ | 32.87 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0915 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1221 |
| Effective Date May 1, 2016 | $/kWh | 0.1840 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

**Effective Date, May 1, 2017**

## GENERAL SERVICE SINGLE PHASE - G1 Service Classification

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Single Phase customers. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES**

| | | |
|---|---|---|
| Service Charge | $ | 33.06 |
| Electricity Rate - First 6,000 kWh | $/kWh | 0.1026 |
| Electricity Rate - Next 7,000 kWh | $/kWh | 0.1361 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

### Effective Date, May 1, 2017

## GENERAL SERVICE THREE PHASE - G3 Service Classification

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Three Phase customers. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES**

| | | |
|---|---|---|
| Service Charge | $ | 41.39 |
| Electricity Rate - First 25,000 kWh | $/kWh | 0.1026 |
| Electricity Rate - Next 15,000 kWh | $/kWh | 0.1361 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
### Effective Date, May 1, 2017

## STREET LIGHTING Service Classification

The energy consumption for street lights is estimated based on Remotes' profile for street lighting load, which provides the amount of time each month that the street lights are operating. Streetlight charges include:

• An energy charge based on installed load, at a rate approved annually (Dollars per kWh x # of fixtures x billing);

• A pole rental charge approved annually, when the light is attached to a Remotes' pole.

Remotes must approve the location of new lighting installations on its poles and the streetlight owner must enter into an agreement to use such poles. Remotes will make the electrical service connection of all streetlights to the distribution system. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES**

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.1017 |

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

### Effective Date, May 1, 2017

## STANDARD A RESIDENTIAL ROAD/RAIL Service Classification

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Aboriginal Affairs and Northern Development Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate - First 250 kWh | $/kWh | 0.6025 |
| Electricity Rate -All Additional kWh | $/kWh | 0.6884 |

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

### Effective Date, May 1, 2017

## STANDARD A RESIDENTIAL AIR ACCESS Service Classification

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are not accessible by a year-round road or by rail.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Electricity Rate - First 250 kWh | $/kWh | 0.9096 |
| Electricity Rate -All Additional kWh | $/kWh | 0.9955 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

**Effective Date, May 1, 2017**

## STANDARD A GENERAL SERVICE ROAD/RAIL Service Classification

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service. This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.6884 |

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

### Effective Date, May 1, 2017

## STANDARD A GENERAL SERVICE AIR ACCESS Service Classification

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:
• Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
• social housing
• a recreational or sports facility
• a radio, television or cable television facility
• a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are not accessible by a year-round road or by rail.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES**

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.9955 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

**Effective Date, May 1, 2017**

## STANDARD A GRID CONNECTED SERVICE Classification

This classification is applicable to all Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:
• Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
• social housing
• a recreational or sports facility
• a radio, television or cable television facility
• a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to all Standard A customers that are connected to the grid.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.3119 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
### Effective Date, May 1, 2017

## microFIT Service Classification

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

Effective Date, May 1, 2016

| | | | |
|---|---|---|---|
| **Price Escalator** | **1.80%** | **Choose Stretch Factor Group** | I |
| **Productivity Factor** | **0.00%** | **Associated Stretch Factor Value** | **0.00%** |
| **Price Cap Index** | **1.80%** | | |

| **Rate Class** | **Current SC** | **1st Tier Current Volumetric Charge** | **2nd Tier Current Volumetric Charge** | **3rd Tier Current Volumetric Charge** | **Price Cap Index to be Applied** | **Proposed SC** | **1st Tier Proposed Volumetric Charge** | **2nd Tier Proposed Volumetric Charge** | **3rd Tier Proposed Volumetric Charge** |
|---|---|---|---|---|---|---|---|---|---|
| RESIDENTIAL | 19.45 | 0.0915 | 0.1221 | 0.1840 | 1.80% | 19.80 | 0.0931 | 0.1243 | 0.1873 |
| SEASONAL RESIDENTIAL | 32.87 | 0.0915 | 0.1221 | 0.1840 | 1.80% | 33.46 | 0.0931 | 0.1243 | 0.1873 |
| GENERAL SERVICE SINGLE PHASE - G1 | 33.06 | 0.1026 | 0.1361 | 0.1840 | 1.80% | 33.66 | 0.1044 | 0.1385 | 0.1873 |
| GENERAL SERVICE THREE PHASE - G3 | 41.39 | 0.1026 | 0.1361 | 0.1840 | 1.80% | 42.14 | 0.1044 | 0.1385 | 0.1873 |
| STREET LIGHTING | 0.00 | 0.1017 | | | 1.80% | 0.00 | 0.1035 | | |
| STANDARD A RESIDENTIAL ROAD/RAIL | 0.00 | 0.6025 | 0.6884 | | 1.80% | 0.00 | 0.6133 | 0.7008 | |
| STANDARD A RESIDENTIAL AIR ACCESS | 0.00 | 0.9096 | 0.9955 | | 1.80% | 0.00 | 0.9260 | 1.0134 | |
| STANDARD A GENERAL SERVICE ROAD/RAIL | 0.00 | 0.6884 | | | 1.80% | 0.00 | 0.7008 | | |
| STANDARD A GENERAL SERVICE AIR ACCESS | 0.00 | 0.9955 | | | 1.80% | 0.00 | 1.0134 | | |
| GRID CONNECTED RATES | | 0.3119 | | | 1.80% | | 0.3175 | | |
| microFIT | 5.40 | | | | | 5.40 | | | |

The following table provides applicants with a class to class comparison of current vs. proposed rates.

Effective Date, May 1, 2017 | Effective Date, May 1, 2018

| Current Rates | | | | Proposed Rates | | |
|---|---|---|---|---|---|---|
| Rate Description | Unit | Amount | | Rate Description | Unit | Amount |
| **RESIDENTIAL** | | | | **RESIDENTIAL** | | |
| Service Charge | $ | 19.45 | | Service Charge | $ | 19.80 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0915 | | Electricity Rate First 1,000 kWh | $/kWh | 0.0931 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1221 | | Electricity Rate Next 1,500 kWh | $/kWh | 0.1243 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 | | Electricity Rate - All Additional kWh | $/kWh | 0.1873 |
| **SEASONAL RESIDENTIAL** | | | | **SEASONAL RESIDENTIAL** | | |
| Service Charge | $ | 32.87 | | Service Charge | $ | 33.46 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0915 | | Electricity Rate First 1,000 kWh | $/kWh | 0.0931 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1221 | | Electricity Rate Next 1,500 kWh | $/kWh | 0.1243 |
| Effective Date May 1, 2016 | $/kWh | 0.1840 | | Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

The following table provides applicants with a class to class comparison of current vs. proposed rates.

| Effective Date, May 1, 2017 | | | | Effective Date, May 1, 2018 | | |
|---|---|---|---|---|---|---|
| **Current Rates** | | | | **Proposed Rates** | | |
| Rate Description | Unit | Amount | | Rate Description | Unit | Amount |
| **GENERAL SERVICE SINGLE PHASE - G1** | | | | **GENERAL SERVICE SINGLE PHASE - G1** | | |
| Service Charge | $ | 33.06 | | Service Charge | $ | 33.66 |
| | | | | | | |
| Electricity Rate - First 6,000 kWh | $/kWh | 0.1026 | | Electricity Rate First 6,000 kWh | $/kWh | 0.1044 |
| | | | | | | |
| Electricity Rate - Next 7,000 kWh | $/kWh | 0.1361 | | Electricity Rate Next 7,000 kWh | $/kWh | 0.1385 |
| | | | | | | |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 | | Electricity Rate - All Additional kWh | $/kWh | 0.1873 |
| | | | | | | |
| **GENERAL SERVICE THREE PHASE - G3** | | | | **GENERAL SERVICE THREE PHASE - G3** | | |
| Service Charge | $ | 41.39 | | Service Charge | $ | 42.14 |
| Electricity Rate - First 25,000 kWh | $/kWh | 0.1026 | | Electricity Rate First 25,000 kWh | $/kWh | 0.1044 |
| Electricity Rate - Next 15,000 kWh | $/kWh | 0.1361 | | Electricity Rate Next 15,000 kWh | $/kWh | 0.1385 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1840 | | Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

The following table provides applicants with a class to class comparison of current vs. proposed rates.

| Effective Date, May 1, 2017 | | | | Effective Date, May 1, 2018 | | |
|---|---|---|---|---|---|---|
| **Current Rates** | | | | **Proposed Rates** | | |
| Rate Description | Unit | Amount | | Rate Description | Unit | Amount |
| **STREET LIGHTING** | | | | **STREET LIGHTING** | | |
| Electricity Rate | $/kWh | 0.1017 | | Electricity Rate | $/kWh | 0.1035 |
| | | | | | | |
| **STANDARD A RESIDENTIAL ROAD/RAIL** | | | | **STANDARD A RESIDENTIAL ROAD/RAIL** | | |
| Electricity Rate - First 250 kWh | $/kWh | 0.6025 | | Electricity Rate - First 250 kWh | $/kWh | 0.6133 |
| | | | | | | |
| Electricity Rate -All Additional kWh | $/kWh | 0.6884 | | Electricity Rate -All Additional kWh | $/kWh | 0.7008 |
| | | | | | | |
| **STANDARD A RESIDENTIAL AIR ACCESS** | | | | **STANDARD A RESIDENTIAL AIR ACCESS** | | |
| Electricity Rate - First 250 kWh | $/kWh | 0.9096 | | Electricity Rate - First 250 kWh | $/kWh | 0.9260 |
| | | | | | | |
| Electricity Rate -All Additional kWh | $/kWh | 0.9955 | | Electricity Rate -All Additional kWh | $/kWh | 1.0134 |
| | | | | | | |
| **STANDARD A GENERAL SERVICE ROAD/RAIL** | | | | **STANDARD A GENERAL SERVICE ROAD/RAIL** | | |
| Electricity Rate | $/kWh | 0.6884 | | Electricity Rate | $/kWh | 0.7008 |
| **STANDARD A GENERAL SERVICE AIR ACCESS** | | | | **STANDARD A GENERAL SERVICE AIR ACCESS** | | |
| Electricity Rate | $/kWh | 0.9955 | | Electricity Rate | $/kWh | 1.0134 |
| **STANDARD A GRID CONNECTED** | | | | **STANDARD A GRID CONNECTED** | | |
| Electricity Rate | $/kWh | 0.3119 | | Electricity Rate | $/kWh | 0.3175 |
| | | | | | | |
| **microFIT** | | | | **microFIT** | | |
| Service Charge | $ | 5.40 | | Service Charge | $ | |

# Effective Date, May 1, 2018

## TARIFF OF RATES AND CHARGES

**Effective Date May 1, 2018**

## YEAR-ROUND RESIDENTIAL - R2 Service Classification

This classification refers to a residential service that is the principal residence of the customer. This classification may include additional buildings served through the same meter, provided they are not rental income units. To be classed as year round residential, all of the following criteria must be met:
- Occupants must state that this is their principal residence for purposes of the Income Tax Act;
- The occupant must live in this residence for at least 8 months of the year;
- The address of this residence must appear on the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.;
- Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 19.80 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0931 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1243 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
**Effective Date May 1, 2018**

## SEASONAL RESIDENTIAL - NORMAL DENSITY [R4] Service Classification

This classification is comprised of any residential service not meeting the year-round residential criteria. As such, the seasonal residential class includes cottages, chalets, and camps. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 33.46 |
| Electricity Rate - First 1,000 kWh | $/kWh | 0.0931 |
| Electricity Rate - Next 1,500 kWh | $/kWh | 0.1243 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

**Effective Date May 1, 2018**

## GENERAL SERVICE SINGLE PHASE - G1 Service Classification

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprise of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Single Phase customers. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 33.66 |
| Electricity Rate - First 6,000 kWh | $/kWh | 0.1044 |
| Electricity Rate - Next 7,000 kWh | $/kWh | 0.1385 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
**Effective Date May 1, 2018**

## GENERAL SERVICE THREE PHASE - G3 Service Classification

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprise of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Three Phase customers. Further servicing details are available in the distributor’s Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 42.14 |
| Electricity Rate - First 25,000 kWh | $/kWh | 0.1044 |
| Electricity Rate - Next 15,000 kWh | $/kWh | 0.1385 |
| Electricity Rate - All Additional kWh | $/kWh | 0.1873 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
**Effective Date May 1, 2018**

## STREET LIGHTING Service Classification

The energy consumption for street lights is estimated based on Remotes' profile for street lighting load, which provides the amount of time each month that the street lights are operating. Streetlight charges include:
• An energy charge based on installed load, at a rate approved annually (Dollars per kWh x # of fixtures x billing);
• A pole rental charge approved annually, when the light is attached to a Remotes' pole.
Remotes must approve the location of new lighting installations on its poles and the streetlight owner must enter into an agreement to use such poles. Remotes will make the electrical service connection of all streetlights to the distribution system. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.1035 |
| | | |

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

**Effective Date May 1, 2018**

## STANDARD A RESIDENTIAL ROAD/RAIL Service Classification

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Aboriginal Affairs and Northern Development Canada. Further servicing details are available in the distributor's Conditions of Service. This classification is applicable to residential customers in communities that are accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Electricity Rate - First 250 kWh | $/kWh | 0.6133 |
| Electricity Rate -All Additional kWh | $/kWh | 0.7008 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
**Effective Date May 1, 2018**

## STANDARD A RESIDENTIAL AIR ACCESS Service Classification

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:
• Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
• social housing
• a recreational or sports facility
• a radio, television or cable television facility
• a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are not accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Electricity Rate - First 250 kWh | $/kWh | 0.9260 |
| Electricity Rate -All Additional kWh | $/kWh | 1.0134 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
**Effective Date May 1, 2018**

## STANDARD A GENERAL SERVICE ROAD/RAIL Service Classification

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:
• Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
• social housing
• a recreational or sports facility
• a radio, television or cable television facility
• a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor’s Conditions of Service. This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 0.7008 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
**Effective Date May 1, 2018**

## STANDARD A GENERAL SERVICE AIR ACCESS Service Classification

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:
• Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
• social housing
• a recreational or sports facility
• a radio, television or cable television facility
• a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor’s Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are not accessible by a year-round road or by rail.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Electricity Rate | $/kWh | 1.0134 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
**Effective Date May 1, 2018**

## STANDARD A GRID CONNECTED Service Classification

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:
• Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
• social housing
• a recreational or sports facility
• a radio, television or cable television facility
• a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor’s Conditions of Service.

This classification is applicable to all Standard A customers in communities that are connected to the grid.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Electricity rate | 0 | 0.3175 |
| | | |

# Hydro One Remote Communities Inc.

## TARIFF OF RATES AND CHARGES

**Effective Date May 1, 2018**

## microFIT Service Classification

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system.  Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# Hydro One Remote Communities Inc.
## TARIFF OF RATES AND CHARGES
### Effective Date May 1, 2018

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential) | $ | 30.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late Payment – per month | % | 1.50 |
| Late Payment – per annum | % | 19.56 |
| Collection/Disconnection/Load Limiter/Reconnection – if in Community | $ | 65.00 |

| | | | |
|---|---|---|---|
| **Effective Date, May 1, 2018** | **YEAR-ROUND RESIDENTIAL** | | |
| **Loss Factor** | | **-** | |
| **Consumption** | **kWh** | **750** | |
| **If Billed on a kW basis:** | | | |
| **Demand** | **kW** | | $ 1.55 |
| **Load Factor** | | | |

| | Current Board-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|
| | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | $ 19.45 | 1 | $ 19.45 | $ 19.80 | 1 | $ 19.80 | $ 0.35 | 1.80% |
| Electricity Rate - First 1,000 kWh | 0.0915 | 750 | $ 68.63 | $ 0.0931 | 750 | $ 69.83 | $ 1.20 | 1.75% |
| Electricity Rate - Next 1,500 kWh | 0.1221 | 0 | $ - | $ 0.1243 | 0 | $ - | $ - | |
| Electricity Rate - All Additional kWh | 0.1840 | 0 | $ - | $ 0.1873 | 0 | $ - | $ - | |
| **Total Bill (Before Taxes)** | | | $ 88.08 | | | $ 89.63 | $ 1.55 | **1.76%** |
| **Total Bill (before Taxes)** | | | **$ 88.08** | | | **$ 89.63** | $ 1.55 | 1.76% |
| HST | 5% | | $ 4.40 | 5% | | $ 4.48 | $ 0.08 | 1.76% |
| **Total Bill** (including HST) | | | $ 92.48 | | | $ 94.11 | $ 1.63 | 1.76% |
| **Total Bill** | | | **$ 92.48** | | | **$ 94.11** | $ 1.63 | **1.76%** |

| | |
|---|---|
| **Rate Class** | **SEASONAL RESIDENTIAL** |
| **Loss Factor** | **-** |
| **Consumption** | **kWh** **250** |
| **If Billed on a kW basis:** | |
| **Demand** | **kW** |
| **Load Factor** | |

| | Current Board-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|
| | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | $ 32.87 | 1 | $ 32.87 | $ 33.46 | 1 | $ 33.46 | $ 0.59 | 1.79% |
| Electricity Rate - First 1,000 kWh | $ 0.0915 | 250 | $ 22.88 | $ 0.0931 | 250 | $ 23.28 | $ 0.40 | 1.75% |
| Electricity Rate - Next 1,500 kWh | $ 0.1221 | 0 | $ - | $ 0.12 | 0 | $ - | $ - | |
| Electricity Rate - All Additional kWh | $ 0.1840 | 0 | $ - | 0.1873 | 0 | $ - | $ - | |
| | | - | $ - | | - | $ - | $ - | |
| **Total Bill (Before Taxes)** | | | $ 55.75 | | | $ 56.74 | **$ 0.99** | **1.78%** |
| | | | | | | | | |
| **Total Bill (before Taxes)** | | | **$ 55.75** | | | **$ 56.74** | **$ 0.99** | **1.78%** |
| HST | 5% | | $ 2.79 | 5% | | $ 2.84 | $ 0.05 | 1.78% |
| **Total Bill** (including HST) | | | $ 58.53 | | | $ 59.57 | $ 1.04 | 1.78% |
| **Total Bill on TOU (including OCEB)** | | | **$ 58.53** | | | **$ 59.57** | **$ 1.04** | **1.78%** |

| | |
|---|---|
| **Rate Class** | **GENERAL SERVICE SINGLE PHASE** |
| **Loss Factor** | **-** |
| **Consumption** | **kWh** **2,000** |
| **If Billed on a kW basis:** | |
| **Demand** | **kW** |
| **Load Factor** | |

| | Current Board-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|
| | **Rate ($)** | **Volume** | **Charge ($)** | **Rate ($)** | **Volume** | **Charge ($)** | **$ Change** | **% Change** |
| Monthly Service Charge | $ 33.06 | 1 | $ 33.06 | $ 33.66 | 1 | $ 33.66 | $ 0.60 | 1.81% |
| Effective Date May 1, 2016 | $ 0.1026 | 2000 | $ 205.20 | $ 0.1044 | 2000 | $ 208.80 | $ 3.60 | 1.75% |
| Electricity Rate - Next 7,000 kWh | $ 0.1361 | 0 | $ - | $ 0.1385 | 0 | $ - | $ - | |
| Electricity Rate - All Additional kWh | $ 0.1840 | 0 | $ - | $ 0.1873 | 0 | $ - | $ - | |
| **Total Bill (Before Taxes)** | | | $ 238.26 | | | $ 242.46 | **$ 4.20** | **1.76%** |
| **Total Bill (before Taxes)** | | | **$ 238.26** | | | **$ 242.46** | **$ 4.20** | **1.76%** |
| HST | 5% | | $ 11.91 | 5% | | $ 12.12 | $ 0.21 | 1.76% |
| **Total Bill** (including HST) | | | $ 250.17 | | | $ 254.58 | $ 4.41 | 1.76% |
| **Total Bill on TOU (including OCEB)** | | | **$ 250.17** | | | **$ 254.58** | **$ 4.41** | **1.76%** |

| | | |
|---|---|---|
| **Rate Class** | **GENERAL SERVICE THREE PHASE** | |
| **Loss Factor** | | **-** |
| **Consumption** | **kWh** | **5,000** |
| **If Billed on a kW basis:** | | |
| **Demand** | **kW** | |
| **Load Factor** | | |

| | Current Board-Approved | | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|---|
| | **Rate ($)** | **Volume** | **Charge ($)** | | **Rate ($)** | **Volume** | **Charge ($)** | **$ Change** | **% Change** |
| Monthly Service Charge | $ 41.39 | 1 | $ 41.39 | | $ 42.14 | 1 | $ 42.14 | $ 0.75 | 1.81% |
| Electricity Rate - First 25,000 kWh | $ 0.1026 | 5000 | $ 513.00 | | $ 0.1044 | 5000 | $ 522.00 | $ 9.00 | 1.75% |
| Electricity Rate - Next 15,000 kWh | $ 0.1361 | 0 | $ - | | $ 0.1385 | 0 | $ - | $ - | |
| Electricity Rate - All Additional kWh | $ 0.1840 | 0 | $ - | | $ 0.1873 | 0 | $ - | $ - | |
| **Total Bill (Before Taxes)** | | | $ 554.39 | | | | $ 564.14 | **$ 9.75** | **1.76%** |
| **Total Bill (before Taxes)** | | | **$ 554.39** | | | | **$ 564.14** | $ 9.75 | **1.76%** |
| HST | 5% | | $ 27.72 | | 5% | | $ 28.21 | $ 0.49 | 1.76% |
| **Total Bill** (including HST) | | | $ 582.11 | | | | $ 592.35 | $ 10.24 | 1.76% |
| **Total Bill** | | | **$ 582.11** | | | | **$ 592.35** | **$ 10.24** | **1.76%** |

| | | |
|---|---|---|
| **Rate Class** | **STREET LIGHTING** | |
| **Loss Factor** | | **-** |
| **Consumption** | **kWh** | **2,000** |
| **If Billed on a kW basis:** | | |
| **Demand** | **kW** | |
| **Load Factor** | | |

| | Current Board-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|
| | **Rate ($)** | **Volume** | **Charge ($)** | **Rate ($)** | **Volume** | **Charge ($)** | **$ Change** | **% Change** |
| Electricity Rate | $ 0.1017 | 2,000 | $ 203.40 | $ 0.1035 | 2,000 | $ 207.00 | $ 3.60 | 1.77% |
| **Total Bill (Before Taxes)** | | | $ 203.40 | | | $ 207.00 | **$ 3.60** | **1.77%** |
| **Total Bill (before Taxes)** | | | **$ 203.40** | | | **$ 207.00** | **$ 3.60** | **1.77%** |
| HST | 5% | | $ 10.17 | 5% | | $ 10.35 | $ 0.18 | 1.77% |
| **Total Bill** (including HST) | | | $ 213.57 | | | $ 217.35 | $ 3.78 | 1.77% |
| **Total Bill (including OCEB)** | | | **$ 213.57** | | | **$ 217.35** | **$ 3.78** | **1.77%** |

| | |
|---|---|
| **Rate Class** | **STANDARD A RESIDENTIAL ROAD-RAIL** |
| **Loss Factor** | **-** |
| **Consumption** | **kWh** **750** |

**If Billed on a kW basis:**

| | |
|---|---|
| **Demand** | **kW** |
| **Load Factor** | |

| | Current Board-Approved | | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|---|
| | Rate ($) | Volume | Charge ($) | | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | $ - | 1 | $ - | | | 1 | $ - | $ - | |
| Electricity Rate First 250 kWh | $ 0.6025 | 250 | $ 150.63 | | $ 0.6133 | 250 | $ 153.33 | $ 2.70 | 1.79% |
| Electricity Rate All Additional kWh | $ 0.6884 | 500 | $ 344.20 | | $ 0.7008 | 500 | $ 350.40 | $ 6.20 | 1.80% |
| **Total Bill (Before Taxes)** | | | **$ 494.83** | | | | **$ 503.73** | **$ 8.90** | **1.80%** |
| | | | | | | | | | |
| **Total Bill (before Taxes)** | | | **$ 494.83** | | | | **$ 503.73** | **$ 8.90** | **1.80%** |
| HST | 5% | | $ 24.74 | | 5% | | $ 25.19 | $ 0.45 | 1.80% |
| **Total Bill** (including HST) | | | $ 519.57 | | | | $ 528.91 | $ 9.35 | 1.80% |
| **Total Bill** | | | **$ 519.57** | | | | **$ 528.91** | $ 9.35 | **1.80%** |

| | | |
|---|---|---|
| **Rate Class** | **STANDARD A RESIDENTIAL AIR ACCESS** | |
| **Loss Factor** | | **-** |
| **Consumption** | **kWh** | **750** |
| **If Billed on a kW basis:** | | |
| **Demand** | **kW** | |
| **Load Factor** | | |

| | Current Board-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|
| | **Rate ($)** | **Volume** | **Charge ($)** | **Rate ($)** | **Volume** | **Charge ($)** | **$ Change** | **% Change** |
| Monthly Service Charge | $ - | 1 | $ - | $ - | 1 | $ - | $ - | |
| Electricity Rate First 250 kWh | $ 0.9096 | 250 | $ 227.40 | $ 0.9260 | 250 | $ 231.50 | $ 4.10 | 1.80% |
| Electricity Rate All Additional kWh | $ 0.9955 | 500 | $ 497.75 | $ 1.0134 | 500 | $ 506.70 | $ 8.95 | 1.80% |
| **Total Bill (Before Taxes)** | | | $ 725.15 | | | $ 738.20 | **$ 13.05** | **1.80%** |
| **Total Bill (before Taxes)** | | | **$ 725.15** | | | **$ 738.20** | **$ 13.05** | **1.80%** |
| HST | 5% | | $ 36.26 | 5% | | $ 36.91 | $ 0.65 | 1.80% |
| **Total Bill** (including HST) | | | $ 761.41 | | | $ 775.11 | $ 13.70 | 1.80% |
| **Total Bill** | | | **$ 761.41** | | | **$ 775.11** | **$ 13.70** | **1.80%** |

| | | | |
|---|---|---|---|
| **Rate Class** | **STANDARD A GENERAL SERVICE ROAD-RAIL** | | |
| **Loss Factor** | | | **-** |
| **Consumption** | **kWh** | | **5,000** |
| **If Billed on a kW basis:** | | | |
| **Demand** | **kW** | | |
| **Load Factor** | | | |

| | Current Board-Approved | | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|---|
| | **Rate ($)** | **Volume** | **Charge ($)** | | **Rate ($)** | **Volume** | **Charge ($)** | **$ Change** | **% Change** |
| Monthly Service Charge | $ - | 1 | $ - | | | 1 | $ - | $ - | |
| Electricity Rate | $ 0.6884 | 5,000 | $ 3,442.00 | | $ 0.7008 | 5,000 | $ 3,504.00 | $ 62.00 | 1.80% |
| **Total Bill (Before Taxes)** | | | **$ 3,442.00** | | | | **$ 3,504.00** | **$ 62.00** | **1.80%** |
| **Total Bill (before Taxes)** | | | **$ 3,442.00** | | | | **$ 3,504.00** | **$ 62.00** | **1.80%** |
| HST | 5% | | $ 172.10 | | 5% | | $ 175.20 | $ 3.10 | 1.80% |
| **Total Bill** (including HST) | | | $ 3,614.10 | | | | $ 3,679.20 | $ 65.10 | 1.80% |
| **Total Bill** | | | **$ 3,614.10** | | | | **$ 3,679.20** | **$ 65.10** | **1.80%** |

| | | | |
|---|---|---|---|
| **Rate Class** | **STANDARD A GENERAL SERVICE AIR ACCESS** | | |
| **Loss Factor** | | **-** | |
| **Consumption** | **kWh** | **5,000** | |
| **If Billed on a kW basis:** | | | |
| **Demand** | **kW** | | |
| **Load Factor** | | | |

| | Current Board-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|
| | **Rate ($)** | **Volume** | **Charge ($)** | **Rate ($)** | **Volume** | **Charge ($)** | **$ Change** | **% Change** |
| Monthly Service Charge | $ - | 1 | $ - | | 1 | $ - | $ - | |
| Electricity Rate | $ 0.9955 | 5,000 | $ 4,977.50 | $ 1.0134 | 5,000 | $ 5,067.00 | $ 89.50 | 1.80% |
| **Total Bill (Before Taxes)** | | | $ 4,977.50 | | | $ 5,067.00 | $ 89.50 | 1.80% |
| **Total Bill (before Taxes)** | | | **$ 4,977.50** | | | **$ 5,067.00** | **$ 89.50** | **1.80%** |
| HST | 5% | | $ 248.88 | 5% | | $ 253.35 | $ 4.48 | 1.80% |
| **Total Bill** (including HST) | | | $ 5,226.38 | | | $ 5,320.35 | $ 93.98 | 1.80% |
| **Total Bill** | | | **$ 5,226.38** | | | **$ 5,320.35** | **$ 93.98** | **1.80%** |

# REGULATORY ACCOUNTS

## 1.0 DESCRIPTION OF REGULATORY ACCOUNTS

Remotes has two Regulatory Accounts: the Rural and Remote Rate Protection Variance Account RRRP (RRRPVA); and an Impact for USGAAP Account.

**(in $K)**

| | **Historic** | | | | **Bridge** |
|---|---|---|---|---|---|
| **Year** | **2013** | **2014** | **2015** | **2016** | **2017 Projected** |
| Rural and Remote Rate Protection (USofA 2405) | 1,985 | 4,579 | 2,760 | 1,644 | 5,262 |
| Impact of USGAAP Account (USofA 1508) | 0 | 0 | 0 | 0 | 0 |
| **Total** | **1,985** | **4,579** | **2,760** | **1,644** | **5,262** |

## 1.1 Remote Rate Protection Variance Account

Remotes conducts its operations under a cost recovery model applied to achieve breakeven results of operations after the inclusion of PILs. Any excess or deficiency in remote rate protection revenues necessary to ensure breakeven results in operations is added to, or drawn from, the RRRPVA. The account was originally established in 2003 pursuant to O.Reg. 442/01. In its RP-2005-0020/EB-2005-0511 Decision, and in its Decision in EB-2012-0137, the Board approved continuation of this account. Detailed information about the balances in this account from 2013 to 2016 can be found as Attachments 1 to 4 of this exhibit. This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

No interest is applied to the RRRPVA given that the intent of the account is to serve as a tool to achieve a break-even operating result. Adding interest would result in a circular impact on the RRRPVA as the interest cost would itself impact that year's operating result, causing a revision to the amount added to or withdrawn from the RRRPVA.

## 2.0 REQUEST FOR DISPOSITION OF ACCOUNTS

It is requested that Remotes' new rates will be effective and implemented on May 1, 2018, and that disposition of the accounts requested will commence on that date.

## 3.0 ESTABLISHMENT OF NEW DEFERRAL AND VARIANCE ACCOUNTS

Remotes does not require the establishment of any new Deferral and/or Variance Accounts.

# CERTIFICATION OF EVIDENCE

TO: ONTARIO ENERGY BOARD

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The undersigned, being Hydro One's Senior Vice President, Finance, Chris Lopez hereby certifies for and on behalf of Hydro One Remote Communities Inc. that:

1. I am the Senior Vice President, Finance of Hydro One;
2. This certificate is given pursuant to section 3.2.5.3 of Chapter 3 of the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (last revised on July 20, 2017); and
3. That Hydro One has robust processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed.

DATED this 28th day of August, 2017.

CHRIS LOPEZ

# REMOTES RURAL AND REMOTE RATE PROTECTION VARIANCE ACCOUNT RECONCILIATION 2013 TO 2016)

Attachment 1: 2013 Rural and Remote Rate Protection Variance Account Reconciliation

Attachment 2: 2014 Rural and Remote Rate Protection Variance Account Reconciliation

Attachment 3: 2015 Rural and Remote Rate Protection Variance Account Reconciliation

Attachment 4: 2016 Rural and Remote Rate Protection Variance Account Reconciliation

**HYDRO ONE REMOTE COMMUNITIES INC**
**Rural and Remote Rate Protection Variance Account Reconciliation 2013**
For the year ended December 31, 2013
(in $K)

| | | Actual Revenues and Expenses (Audited) | | Approved | Variance |
|---|---|---|---|---|---|
| **RRRP Variance Account, Opening Balance** | **1-Jan-2013** | | **787** | | |
| Annual Rural and Remote Rate Protection | | (32,259) | | (32,259) | |
| RRRP Variance Account Recovery | | (787) | | (787) | |
| **Total RRRP received** | | **(33,046)** | **(33,046)** | **(33,046)** | |
| **Revenues** | | | | | |
| Energy | | (14,985) | | (17,260) | (2,275) |
| Other - Late Payment, Service Fees, External | | (805) | | (586) | 219 |
| **Total Revenues** | **Note 1** | **(15,790)** | **(15,790)** | **(17,846)** | **(2,056)** |
| **Costs - OM&A** | | | | | |
| Generation | | 12,966 | | 10,585 | 2,381 |
| Fuel | | 25,568 | | 24,067 | 1,501 |
| Power purchased | | 0 | | 1,980 | (1,980) |
| Distribution | | 1,461 | | 2,980 | (1,519) |
| Customer care | | 2,844 | | 1,855 | 989 |
| Community relations | | 520 | | 750 | (230) |
| Administration and other OM&A | | 1,427 | | 1,157 | 270 |
| External costs | | 206 | | 61 | 145 |
| Bad debt expense (recovery) | | 220 | | 48 | 172 |
| Depreciation | | 3,169 | | 3,317 | (148) |
| Amortization of environmental assets | | 1,656 | | 1,861 | (205) |
| Interest | | 1,088 | | 1,631 | (543) |
| Income taxes | | (1,091) | | (187) | (904) |
| **Total Costs** | | **50,034** | **50,034** | **50,105** | **(71)** |
| **Net (Income)/Loss [change in RRRP]** | | 1,198 | | | |
| **RRRP Variance Account, Ending Balance** | **31-Dec-2013** | | **1,985** | | |

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2013 were $33,046 thousand. An additional $1,198 thousand was recognized as revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

**HYDRO ONE REMOTE COMMUNITIES INC**
**Rural and Remote Rate Protection Variance Account Reconciliation 2014**
For the year ended December 31, 2014
(in $K)

| | | Actual Revenues and Expenses (Audited) | | Approved | Variance |
|---|---|---|---|---|---|
| **RRRP Variance Account, Opening Balance** | **1-Jan-2014** | | **1,985** | | |
| Annual Rural and Remote Rate Protection | | (32,259) | | (32,259) | |
| RRRP Variance Account Recovery | | 0 | | 0 | |
| **Total RRRP received** | | **(32,259)** | **(32,259)** | **(32,259)** | |
| **Revenues** | | | | | |
| Energy | | (16,784) | | (17,260) | (476) |
| Other - Late Payment, Service Fees, External | | (494) | | (586) | (92) |
| **Total Revenues** | **Note 1** | **(17,278)** | **(17,278)** | **(17,846)** | **(568)** |
| **Costs - OM&A** | | | | | |
| Generation | | 14,242 | | 10,585 | 3,657 |
| Fuel | | 25,869 | | 24,067 | 1,802 |
| Power purchased | | 0 | | 1,980 | (1,980) |
| Distribution | | 1,879 | | 2,980 | (1,101) |
| Customer care | | 1,906 | | 1,855 | 51 |
| Community relations | | 554 | | 750 | (196) |
| Administration and other OM&A | | 1,492 | | 1,157 | 335 |
| External costs | | 172 | | 61 | 111 |
| Bad debt expense (recovery) | **Note 2** | (175) | | 48 | (223) |
| Depreciation | | 3,040 | | 3,317 | (277) |
| Amortization of environmental assets | | 1,599 | | 1,861 | (262) |
| Interest | | 1,543 | | 1,631 | (88) |
| Income taxes | | 10 | | (187) | 197 |
| **Total Costs** | | **52,131** | **52,131** | **50,105** | **2,026** |
| **Net (Income)/Loss [change in RRRP]** | | 2,594 | | | |
| **RRRP Variance Account, Ending Balance** | **31-Dec-2014** | | **4,579** | | |

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2014 were $32,259 thousand. An additional $2,594 thousand was recognized as revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $175 thousand reflects the impact of lower energy receivables due to successful long term payment arrangements and vigorous residential collections.

**HYDRO ONE REMOTE COMMUNITIES INC**
**Rural and Remote Rate Protection Variance Account Reconciliation 2015**
For the year ended December 31, 2015
(in $K)

| | | Actual Revenues and Expenses (Audited) | | Approved | Variance |
|---|---|---|---|---|---|
| **RRRP Variance Account, Opening Balance** | **1-Jan-2015** | | **4,579** | | |
| Annual Rural and Remote Rate Protection | | (32,259) | | (32,259) | |
| RRRP Variance Account Recovery | | 0 | | 0 | |
| **Total RRRP received** | | **(32,259)** | **(32,259)** | **(32,259)** | |
| **Revenues** | | | | | |
| Energy | | (16,272) | | (17,260) | (988) |
| Other - Late Payment, Service Fees, External | | (1,608) | | (586) | 1,022 |
| **Total Revenues** | **Note 1** | **(17,880)** | **(17,880)** | **(17,846)** | **34** |
| **Costs - OM&A** | | | | | |
| Generation | | 12,957 | | 10,585 | 2,372 |
| Fuel | | 23,250 | | 24,067 | (817) |
| Power purchased | | 0 | | 1,980 | (1,980) |
| Distribution | | 2,415 | | 2,980 | (565) |
| Customer care | | 1,733 | | 1,855 | (122) |
| Community relations | | 291 | | 750 | (459) |
| Administration and other OM&A | | 1,307 | | 1,157 | 150 |
| External costs | | 264 | | 61 | 203 |
| Bad debt expense (recovery) | **Note 2** | (1,105) | | 48 | (1,153) |
| Depreciation | | 3,697 | | 3,317 | 380 |
| Amortization of environmental assets | | 1,222 | | 1,861 | (639) |
| Interest | | 1,661 | | 1,631 | 30 |
| Income taxes | | 628 | | (187) | 815 |
| **Total Costs** | | **48,320** | **48,320** | **50,105** | **(1,785)** |
| **Net (Income)/Loss [change in RRRP]** | | (1,819) | | | |
| **RRRP Variance Account, Ending Balance** | **31-Dec-2015** | | **2,760** | | |

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2015 were $32,259 thousand. Of that, $30,440 thousand was recognized as revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $1,105 thousand primarily reflects the successful early completion of a long term payment plan.

**HYDRO ONE REMOTE COMMUNITIES INC**
**Rural and Remote Rate Protection Variance Account Reconciliation 2016**
For the year ended December 31, 2016
(in $K)

| | | Actual Revenues and Expenses (Audited) | | Approved | Variance |
|---|---|---|---|---|---|
| **RRRP Variance Account, Opening Balance** | **1-Jan-2016** | | **2,760** | | |
| Annual Rural and Remote Rate Protection | | (32,259) | | (32,259) | |
| RRRP Variance Account Recovery | | 0 | | 0 | |
| **Total RRRP received** | | **(32,259)** | **(32,259)** | **(32,259)** | |
| **Revenues** | | | | | |
| Energy | | (17,658) | | (17,260) | 398 |
| Other - Late Payment, Service Fees, External | | (1,556) | | (586) | 970 |
| **Total Revenues** | **Note 1** | **(19,214)** | **(19,214)** | **(17,846)** | **1,368** |
| **Costs - OM&A** | | | | | |
| Generation | | 13,931 | | 10,585 | 3,346 |
| Fuel | | 23,669 | | 24,067 | (398) |
| Power purchased | | 0 | | 1,980 | (1,980) |
| OESP Payments to IESO | | 61 | | 0 | 61 |
| Distribution | | 1,991 | | 2,980 | (989) |
| Customer care | | 1,897 | | 1,855 | 42 |
| Community relations | | 138 | | 750 | (612) |
| Administration and other OM&A | | 1,487 | | 1,157 | 330 |
| External costs | | 342 | | 61 | 281 |
| Bad debt expense (recovery) | **Note 2** | (21) | | 48 | (69) |
| Depreciation | | 3,392 | | 3,317 | 75 |
| Amortization of environmental assets | | 1,247 | | 1,861 | (614) |
| Interest | | 1,776 | | 1,631 | 145 |
| Income taxes | | 447 | | (187) | 634 |
| **Total Costs** | | **50,357** | **50,357** | **50,105** | **252** |
| **Net (Income)/Loss [change in RRRP]** | | (1,116) | | | |
| **RRRP Variance Account, Ending Balance** | **31-Dec-2016** | | **1,644** | | |

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2016 were $32,259 thousand. Of that, $31,143 thousand was recognized as revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $21 thousand reflects the impact of lower energy receivables due to successful long term paymen arrangements and vigorous residential collections.