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Joanne Richardson
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

January 20, 2017

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

Dear Ms. Walli:

EB-2016-0276 – Hydro One Networks Inc. MAAD S86 to Purchase all of the issued and outstanding shares of Orillia Power Distribution Corporation – Interrogatory Responses

As per Procedural Order No. 2, please find attached Hydro One Networks Inc.'s responses to interrogatory questions received in regards to the above-noted proceeding.

The interrogatory responses have been organized by party as indicated below:

Tab 1	Board Staff
Tab 2	Mr Frank Kehoe
Tab 3	Vulnerable Energy Consumers Coalition
Tab 4	Consumers Council of Canada
Tab 5	School Energy Coalition

An electronic copy of this cover letter and the attached interrogatory responses has been filed through the Ontario Energy Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson
Attach.
cc. Parties of EB-2016-0276 (electronic only)

Ontario Energy Board (Board Staff) INTERROGATORY #1

Interrogatory:

Ref: Exh A/T1/Sch1/p.2
Attachments 1 and 3

A corporate organizational chart of Hydro One Inc. (Hydro One), before and after the transaction, is provided as Attachment 1 and a similar corporate organizational chart of Orillia Power Distribution Corporation (Orillia Power) is provided as Attachment 3.

a) Please confirm that the Hydro One post-acquisition chart represents the organizational structure immediately after the closing of the transaction and prior to the integration of Orillia Power into Hydro One Networks Inc.

b) Please provide a copy of By Law 2000-144 setting out the conveyance of the distribution system from Orillia Water, Light and Power Commission to Orillia Power.

Response:

a) Confirmed.

b) A copy of the By Law 2000-144 is provided as Attachment 1. By Law 2000-155, which clarifies a section in 2000-144, is also provided as Attachment 2.

Revised October 16, 2000

THE CORPORATION OF THE CITY OF ORILLIA

BY-LAW NO. 2000-144

A BY-LAW TO TRANSFER CERTAIN ASSETS, LIABILITIES, EMPLOYEES, RIGHTS AND OBLIGATIONS OF THE ORILLIA WATER, LIGHT AND POWER COMMISSION AND THE CORPORATION OF THE CITY OF ORILLIA USED IN THE DISTRIBUTION, RETAILING AND GENERATION OF ELECTRICITY TO CORPORATIONS TO BE INCORPORATED UNDER THE BUSINESS CORPORATIONS ACT (ONTARIO) PURSUANT TO SECTION 142 OF THE ELECTRICITY ACT, 1998 (ONTARIO) AND SECTION 71 AND SECTION 73 OF THE ONTARIO ENERGY BOARD ACT, 1998 (ONTARIO), AND TO EFFECT AN EXCHANGE OF SHARES AMONGST THE SAID CORPORATIONS

RECITALS

1. The City distributes, retails and generates electricity through the Commission.

2. The Council wishes to incorporate Holdco, Distco and Genco under the O.B.C.A. pursuant to Section 142 of the Electricity Act and Sections 71 and 73 of the Ontario Energy Board Act.

3. The Council wishes to transfer certain assets, liabilities, employees, rights and obligations of the Commission and the City relating to the distribution, retailing and generation of electricity on and subject to the terms and conditions set forth herein.

4. Subsection 145(1) of the Electricity Act authorizes the Council to make By-laws to effect such a transfer.

5. The Council wishes to effect an exchange of shares amongst Holdco, Distco and Genco.

NOW THEREFORE THE COUNCIL OF THE CORPORATION OF THE CITY OF ORILLIA HEREBY ENACTS AS FOLLOWS:

SECTION 1 - INTERPRETATION

1.01 Definitions

Whenever used in this By-law, including the Recitals, unless the context otherwise requires, the words and terms set out in Schedule "A" hereto have the respective meanings ascribed to them in Schedule "A".

1.02 Extended Meanings

In this By-law words importing the singular number include the plural and vice versa, and words importing gender shall include all genders.

1.03 Applicable Law

This By-law and all documents, instruments, agreements and transfers contemplated hereby shall be construed and enforced in accordance with the laws of the Province of Ontario.

1.04 Schedules

The following Schedules are attached to and form part of this By-law.

(a) Schedule "A" - Definitions
(b) Schedule "B" - Shareholder Declaration and Direction
(c) Schedule "C" - Holdco Assets and Holdco Liabilities

(d) Schedule "C-1" - Holdco Financial Schedule Illustrating Transfer
(e) Schedule "D" - Distco Assets and Distco Liabilities
(f) Schedule "D-1" - Distco Financial Schedule Illustrating Transfer
(g) Schedule "D-2" - Distco Promissory Note Terms
(h) Schedule "E" - Genco Assets and Genco Liabilities
(i) Schedule "E-1" - Genco Financial Schedule Illustrating Transfer
(j) Schedule "E-2" - Genco Promissory Note Terms
(k) Schedule "F" - Excluded Assets and Excluded Liabilities
(l) Schedule "G" - Distco Employees Transferred and Collective Agreements
(m) Schedule "H" - Genco Employees Transferred and Collective Agreements

SECTION 2 - INCORPORATION

2.01 Authorization

The Council hereby authorizes the incorporation and organization of Holdco, Distco and Genco to continue (subject to any approval required by the Shareholder Declaration and Direction attached hereto as Schedule "B") the distribution, retailing and generation of electricity carried on through the Commission and as authorized by the Electricity Act and the Ontario Energy Board Act.

2.02 Subscription for Shares

In order to effect the initial organization of Holdco, Distco and Genco the City is authorized to subscribe and pay for one common share of each of the said corporations at a consideration of $10.00 per share.

2.03 Shareholder Declaration and Direction

The City, in its capacity as initial Shareholder of Holdco, Distco and Genco, shall execute and deliver the Shareholder Declaration and Direction to provide for the organization, management and administration of the said Corporations in the form attached hereto as Schedule "B".

SECTION 3 - TRANSFERS

3.01 Transfer to Holdco

As of the Effective Date, except as otherwise provided for in this By-law, the City transfers to Holdco all the Holdco Assets and Holdco Liabilities, and Holdco accepts and assumes such assets and liabilities.

3.02 Transfer to Distco

As of the Effective Date, except as otherwise provided for in this By-law, the City transfers to Distco all the Distco Assets, Distco Liabilities and Distco Employees of the Commission and the City, and Distco accepts and assumes such assets, liabilities and employees.

3.03 Transfer to Genco

As of the Effective Date, except as otherwise provided for in this By-law, the City transfers to Genco all the Genco Assets, Genco Liabilities and Genco Employees of the Commission and the City, and Genco accepts and assumes such assets, liabilities and employees.

3.04 Employees

As of the Effective Date the service of the Employees with the Commission shall be deemed to be service with Distco or Genco, as the case may be, for the purpose of determining probationary periods, benefits or any other employment-related entitlements under the Employment Standards Act, or any other Act or under any employment contract or Collective Agreement and the Employees shall cease to be employees of the Commission and shall thereupon be employees of Distco or Genco, as the case may be, without interruption in service.

3.05 Reserves

As of the Effective Date the City transfers to Distco the Development Charge Reserves.

3.06 Excluded Assets and Excluded Liabilities

The transfer of any assets and liabilities pursuant to this By-law shall not include the Excluded Assets and Excluded Liabilities which shall remain the assets and liabilities of the City.

3.07 Transfer and Delivery of Assets

Each of the City and the Commission shall execute and deliver to Holdco, Distco and Genco, as the case may be, in a form suitable for registration, recording and filing with such public authorities as may be reasonably required, all such bills of sale, assignments, instruments of transfer, assurances, consents and other documents as shall be necessary to effectively record the transfer to Holdco, Distco and Genco of all of the City's, and the Commission's, right, title and interest in, to and under, or in respect of, the Holdco Assets, the Distco Assets and the Genco Assets respectively.

3.08 Transfer and Delivery of Excluded Assets

The Commission shall execute and deliver to the City, in a form suitable for registration, recording and filing with such public authorities as may be reasonably required, all such bills of sale, assignments, instruments of transfer, assurances, consents and other documents as shall be necessary to effectively record the transfer, to the City, of all of the Commission's right, title and interest in, to and under, or in respect of, the Excluded Assets.

3.09 Non-Assignable Assets

Notwithstanding any other provision of this By-law or the Electricity Act, if any of the assets transferred to the Transferee Corporation pursuant to this By-law shall not be assignable, or shall only be assignable with the consent or approval of a third party, the City or the Commission as the case may be shall:

(a) use all reasonable efforts in co-operation with the Transferee Corporation to secure the consent or approval required and all costs of obtaining such consent shall be paid by the Transferee Corporation; and

(b) pending the effective transfer thereof, hold all rights or entitlement that the City or the Commission has thereto in trust for the exclusive benefit of the Transferee Corporation provided that the Transferee Corporation shall pay, perform and discharge all obligations arising or accruing with respect thereto during such period. The Transferee Corporation shall indemnify and save harmless the City and the Commission with respect to such obligations.

3.10 Subsequent Transfers

Any of the assets, assumed liabilities and Employees which are transferred pursuant to this By-law may, from time to time, and subject to the provisions of the Electricity Act, be subsequently transferred to Holdco, Distco or Genco on such terms and for such consideration as recommended by Holdco and approved by the Council and any such subsequent transfer shall be made pursuant to the authority granted by this By-law and shall take effect in the sequence and at such times as set out in the subsequent transfer.

3.11 Costs

All transition costs and expenses incurred or to be incurred by the City, and all taxes (including transfer taxes) incurred or payable in connection with the incorporation of Holdco, Distco or Genco and any transfers contemplated or carried out pursuant to this By-law shall be paid by Distco and/or Genco which shall reimburse the City on demand for any such costs, expenses or taxes.

SECTION 4 - PURCHASE PRICE

4.01 Purchase Price

The purchase price payable by Holdco for the Holdco Assets, by Distco for the Distco Assets, and by Genco for the Genco Assets shall be equal to the fair market value thereof as of the Effective Date. As the determination of the fair market value is dependent upon information not presently available and criteria not yet finalized, such value shall be deemed to be book value as shown on the 1999 Audited Financial Statements of the Commission subject to adjustment pursuant to Section 4.05 of this By-law.

4.02 Satisfaction of Purchase Price for Holdco Assets

In full payment and satisfaction of the purchase price for the Holdco Assets Holdco shall allot and issue to the City 1,000 fully paid and non-assessable common shares of Holdco having an ascribed value equal to the purchase price and the amount of such value shall be added to the stated capital account for such shares.

4.03 Satisfaction of Purchase Price for Distco Assets

In full payment and satisfaction of the purchase price for the Distco Assets Distco shall:

(a) be bound by, assume, pay, satisfy, discharge, observe, perform and fulfill the Distco Liabilities including any obligations to the Distco Employees;

(b) and as to the balance of the purchase price

i) allot and issue to the City 1,000 fully paid and non-assessable common shares of Distco having an ascribed value equal to 50% of such balance and the amount of such value shall be added to the stated capital account for such shares; and

ii) issue to the City a Promissory Note having a principal amount equal to 50% of such balance on the terms as set out in Schedule "D-2" hereto. The Promissory Note shall be secured by a General Security Agreement which shall form a first priority security interest in the Distco Assets, present and future.

4.04 Satisfaction of Purchase Price for Genco Assets

In full payment and satisfaction of the purchase price for the Genco Assets Genco shall:

(a) be bound by, assume, pay, satisfy, discharge, observe, perform and fulfill the Genco Liabilities including any obligations to the Genco Employees;

(b) and as to the balance of the purchase price

i) allot and issue to the City 1,000 fully paid and non-assessable common shares of Genco having an ascribed value equal to 30% of such balance and the amount of such value shall be added to the stated capital account for such shares; and

ii) issue to the City a Promissory Note having a principal amount equal to 70% of such balance on the terms as set out in Schedule "E-2" hereto. The Promissory Note shall be secured by a General Security Agreement which shall form a first priority security interest in the Genco Assets, present and future.

4.05 Adjustment of Purchase Prices and Payment

The purchase prices for the Holdco Assets, the Distco Assets and the Genco Assets, and the manner in which the purchase price is satisfied, may be adjusted as a result of any audit or valuation conducted after the Effective Date with respect to the assets and liabilities transferred to Holdco, Distco or Genco as of the Effective Date. In addition, the basis for the fair market value of the Distco Assets involves a consideration of the permitted rate of return on equity, and the distribution rates that the OEB will allow Distco to charge for the distribution of electricity. The fair market value of the Distco Assets and the manner in which the purchase price is satisfied for such assets may be adjusted as a consequence of any determination of the permitted distribution rates by the OEB or arising from any other legislative or regulatory matter that has not yet been finalized or is subsequently amended.

4.06 Manner of Effecting Adjustments of Purchase Price and Payment

Any adjustments contemplated by Section 4.05 may be effected by the Treasurer of the City in consultation with Holdco and approved by the Council. Such adjustments may result in an adjustment to the number of common shares issued, the stated capital of such shares, the principal amount of any Promissory Note, or any combination thereof. All necessary adjustments made pursuant to this Section shall have the same effect as if they were made on the Effective Date.

4.07 Allocation of Purchase Price

The purchase price shall be allocated among the Holdco Assets, the Distco Assets and Genco Assets as determined by Holdco.

4.08 Indemnity

Holdco, Distco and Genco shall indemnify and save harmless the City and the Commission from and against the liabilities assumed by them. The Holdco Liabilities may be enforced only against Holdco, the Distco Liabilities may be enforced only against Distco, the Genco Liabilities may be enforced only against Genco, and the City and the Commission are hereby released from any liability or obligation therewith as of the Effective Date.

4.09 Rights and Liabilities Transferred

Any rights and liabilities transferred by this By-law to Holdco, Distco or Genco may only be enforced by and against the respective corporation and may not be enforced by and against the City or the Commission as of the Effective Date.

4.10 Transfer of Shares

All of the common shares of Distco and Genco issued to the City pursuant to Sections 4.03 and 4.04 of this By-law shall be transferred to Holdco by the City as of the Effective Date in exchange for the allotment and issuance by Holdco to the City of an additional 1,000 fully paid and non-assessable common shares of Holdco.

SECTION 5 - GENERAL MATTERS

5.01 Regulatory Approvals

It is not anticipated that any regulatory approvals are required to implement this By-law. If it should be determined in the future that any approvals are required then such approvals may be sought by the City, Holdco, Distco or Genco and following the receipt of any such approvals the transfer herein shall be completed with effect as of the Effective Date pursuant to this By-law.

5.02 Goods and Services Tax (Section 167 Exemption)

The transfer of any assets pursuant to this By-law will constitute the transfer of all or substantially all of the assets necessary for the Transferee Corporation to carry on the business transferred to it. The City and the Transferee Corporation, being registered pursuant to the Excise Tax Act (Canada) with respect to Goods and Services Tax, shall sign the election provided for in Section 167 of the said Act and the Transferee Corporation shall file the election in accordance with the said Section so that the transfer is exempt from Goods and Services Tax.

5.03 Amendment of By-law

In the event of any omission or error made in the connection with the passage of this By-law, including without limitation, the unintended transfer or failure to transfer any assets, liabilities or Employees of the Commission and/or the City, the City may amend this By-law and any such amendment or amendments shall be deemed to take effect as of the Effective Date.

5.04 Further Assurances

The City and the Commission shall, at the expense of Distco and/or Genco, promptly and duly execute and deliver such further documents and promptly take such further action not inconsistent with the terms hereof as may from time to time be reasonably required to more effectively carry out the intent and purpose of this By-law or to perfect and protect the interest of the Transferee Corporation with respect to the assets transferred to it. The Mayor and the Clerk are hereby authorized and directed, for and on behalf of the City, to do all acts and things and execute and deliver such other documents, instructions, agreements and transfers as may be reasonably necessary or desirable to give effect to the provisions of this By-law.

5.05 Binding Effect

As provided in Section 145 of the Electricity Act this By-law is binding on the City, the Commission, Holdco, Distco, Genco and all other persons. The City, Holdco, Distco, or Genco may register such documents, instruments and agreements, including, without limitation, certified copies of this By-law, as may be necessary or desirable in order to evidence or confirm the transfers provided for herein.

5.06 Severability

If any section of this By-law or part thereof is invalid or ultra vires such section or part shall not affect the remaining sections or parts of this By-law.

5.07 Successors and Assigns

This By-law shall enure to the benefit of and shall be binding upon and enforceable by the City, the Commission, Holdco, Distco and Genco and their respective successors and assigns.

BY-LAW READ A FIRST, SECOND AND THIRD TIME AND FINALLY PASSED THIS 16th DAY OF October, 2000.

M Buchanan
Maggie Buchanan, Acting Mayor

Laura S. Lee
Laura S. Lee, Clerk

CERTIFIED TO BE A TRUE AND CORRECT COPY OF BY-LAW NUMBER 2000-144

Laura S. Lee
CITY CLERK

DATE October 17, 2000

SCHEDULE "A" - DEFINITIONS

1. "City" means The Corporation of the City of Orillia.

2. "Collective Agreement" means any agreement listed in Schedules "G" and "H" hereto.

3. "Commission" means the Orillia Water, Light and Power Commission.

4. "Council" means the Council of The Corporation of the City of Orillia.

5. "Development Charge Reserves" means the portion of any reserve fund established under Section 33 of the Development Charges Act, 1997 that relates to development charges collected in respect of electrical power services and the portion of any reserve fund referred to in Section 63 of the Development Charges Act, 1997 that relates to development charges collected in respect of electrical power services.

6. "Distco" means Orillia Power Distribution Corporation.

7. "Distco Assets" means all of the right, title and interest in those assets listed in Schedule "D" hereto.

8. "Distco Employees" means those Employees set out in Schedule "G" hereto.

9. "Distco Liabilities" means all of the liabilities listed in Schedule "D" hereto.

10. "Effective Date" means November 1, 2000.

11. "Electricity Act" means the Electricity Act, 1998 (Ontario) and any Regulations made thereunder as amended or replaced from time to time.

12. "Employees" means all full-time and part-time, union and non-union, employees and officers of the Commission as at the Effective Date.

13. "Excluded Assets" means those assets of the City or the Commission set out in Schedule "F" hereto.

14. "Excluded Liabilities" means those liabilities of the City or the Commission set out in Schedule "F" hereto.

15. "Genco" means Orillia Power Generation Corporation.

16. "Genco Assets" means all of the right, title and interest in those assets listed in Schedule "E" hereto.

17. "Genco Employees" means those Employees set out in Schedule "H" hereto.

18. "Genco Liabilities" means all of the liabilities listed in Schedule "E" hereto.

19. "Holdco" means Orillia Power Corporation.

20. "Holdco Assets" means all of the right, title and interest in those assets listed in Schedule "C" hereto

21. "Holdco Liabilities" means all of the liabilities listed in Schedule "C" hereto.

22. "O.B.C.A." means the Business Corporations Act (Ontario) and any Regulations made thereunder as amended or replaced from time to time.

23. "O.E.B." means the Ontario Energy Board.

24. "Ontario Energy Board Act" means the Ontario Energy Board Act, 1998 (Ontario) and any Regulations made thereunder as amended or replaced from time to time.

25. "Transferee Corporation" means any of Holdco, Distco or Genco as the context so requires

SCHEDULE "B"
Revised October 16, 2000

CITY OF ORILLIA
SHAREHOLDER DECLARATION AND DIRECTION

1. DEFINITIONS

    (a) "Corporation" shall mean Orillia Power Corporation.

    (b) "Distco" shall mean Orillia Power Distribution Corporation.

    (c) "Genco" shall mean Orillia Power Generation Corporation.

    (d) "OBCA" shall mean the Business Corporations Act (Ontario) as amended or replaced from time to time.

    (e) "OEB" shall mean the Ontario Energy Board.

    (f) "Shareholder" shall mean the Corporation of the City of Orillia.

    (g) "Subsidiaries" shall mean Distco and Genco.

2. PURPOSE

The purpose of this Declaration is to define the framework for the governance of the Corporation and the Subsidiaries, and to establish policies and principles for their management. This Declaration is not intended to constitute a unanimous Shareholder Declaration under the OBCA except as provided in Paragraphs 7(c), 10 and 11.

3. AUTHORIZED BUSINESS ACTIVITIES

    (a) Subject to the requirements of the Energy Competition Act, the OEB , and all other applicable regulatory and governmental authorities, the Corporation and the Subsidiaries may engage in the following authorized business activities:

        (1) Distributing electricity;

(2) Business activities that develop or enhance the ability of the Corporation or the Subsidiaries to carry on the activity set out in (1) above;

(3) Business activities the principal purpose of which is to use more effectively the assets of the distributor or an affiliate of the distributor including providing meter installation and reading services, and providing billing services;

(4) Generating electricity;

(5) Providing telecommunications and fibre-optics services;

(6) Participation in the Upper Canada Energy Alliance;

(7) Providing services related to improving energy efficiency.

(b) Notwithstanding Paragraph 3(a)(5) above, the Board of Directors of the Corporation shall undertake a review of the commercial viability of the telecommunications and fibre-optics business formerly operated by the Orillia Water, Light and Power Commission on a priority basis in the first full fiscal year of the Corporation.

4. <u>SUBSIDIARIES</u>

(a) Distco is a subsidiary of the Corporation and its principal business activity will be distributing electricity.

(b) Genco is a subsidiary of the Corporation and its principal business activity will be generating electricity.

5. <u>BOARD OF DIRECTORS OF THE CORPORATION</u>

(a) <u>Number of Directors</u>

The Corporation shall be managed by the Board of Directors and the initial Board shall consist of 5 Directors to be elected by the Shareholder.

(b) Qualification of Directors

(1) The Board of Directors should be composed of persons having the following desirable mix of complementary skills and experience:

(i) experience in company governance, corporate financial structuring, competitive market development, or corporate structural transitions;

(ii) experience in a regulated environment, a competitive wholesale or retail environment, a monopolistic service or utility, or the public sector;

(iii) skills in marketing, finance, human resources, communications, corporate and energy law, health and safety, or labour relations.

(2) Non-residents of the City of Orillia may qualify as candidates for the Board of Directors.

(3) No person shall serve as a Director while that person is a member of the Council of the Corporation of the City of Orillia.

(4) No person shall serve as a Director while that person is an employee of the Corporation of the City of Orillia.

(c) Term

The term for each Director shall be as follows:

(1) Directors shall be elected for a term of 3 years on a rotational basis except for the initial 5 Directors who shall be elected as follows:

(i) 1 for a 1 year term;
(ii) 2 for a 2 year term; and
(iii) 2 for a 3 year term.

(2) Any Director may serve for any number of successive terms as determined by the Shareholder.

(d) Directors' Compensation

The compensation for Directors shall be determined by the Shareholder from time to time. The Chair may receive greater compensation than the other Directors.

(e) Chair and Vice-Chair

The Directors shall elect a Chair and Vice-Chair from amongst themselves.

6. BOARD OF DIRECTORS OF DISTCO AND GENCO

(a) Number of Directors

The Corporation is encouraged to minimize the number of Directors to be elected to the Boards of Distco and Genco. Each Board may consist of only 1 Director. The choosing of Directors for each Board shall be in compliance with the Affiliate Relationships Code as established by the OEB.

(b) Responsibilities

The Corporation shall ensure that the management of Distco and Genco, by their Boards of Directors, shall be subject to Shareholder Declarations of the Corporation which will effectively transfer all responsibility for such management to the Board of Directors of the Corporation and which will be consistent with this Shareholder Declaration.

(c) Qualification of Directors

(1) No person shall serve as a Director while that person is a member of the Council of the Corporation of the City of Orillia.

(2) No person shall serve as Director while that person is an employee of the Corporation of the City of Orillia.

(3) Non-residents of the City of Orillia may qualify as candidates for the Board of Directors.

(4) Senior employees of Distco or Genco may qualify as candidates for the Board of Directors.

(d) Term

The term for each Director shall be as follows:

(1) Directors shall be elected for a 1 year term;

(2) Any Director may serve for any number of successive terms as determined by the Corporation.

(e) Directors' Compensation

The compensation for Directors shall be determined by the Corporation from time to time. Employees who also serve as Directors may not be entitled to any additional compensation.

7. FINANCIAL POLICIES

(a) Distco

The Shareholder expects that the Corporation through its Board of Directors will establish policies to maximize the return to the Shareholder to the extent permitted by the OEB over a transition period of 3 to 5 years.

(b) Genco

The Shareholder expects that the Corporation through its Board of Directors will establish policies to move to a profit maximization approach over a transition period of 3 to 5 years.

(c) Dividends

The declaration and payment of dividends by the Corporation shall require the approval of the Shareholder and such approval shall be obtained prior to January 31st in the year in which such dividends are to be paid.

8. SHAREHOLDER REPRESENTATIVE

The Shareholder hereby designates the Clerk of the Corporation of the City of Orillia as the legal representative of the Shareholder for purposes of communicating to the Board of Directors of the Corporation any consent or approval required by this Shareholder Declaration or by the OBCA.

9. DECISIONS OF THE SHAREHOLDER

Any consent or approval of the Shareholder required pursuant to this Shareholder Declaration or the OBCA shall require a Resolution or By-law of the Council of the Shareholder passed at a meeting of the Council, and shall be communicated in writing signed by the Shareholder representative.

10. MATTERS REQUIRING SHAREHOLDER APPROVAL UNDER THE OBCA

Without Shareholder approval neither the Corporation nor the Subsidiaries shall:

(a) Amend its Articles;

(b) Make a new by-law, amend a by-law or repeal a by-law;

(c) Amalgamate (unless amalgamation involves one or more subsidiaries), apply to continue as a corporation in another jurisdiction, merge, consolidate, or reorganize, or approve or effect any plan of arrangement, in each case whether statutory or otherwise;

(d) Initiate proceedings to wind up, dissolve, or reorganize the corporation unless such reorganization is authorized under S.186 of the OBCA;

(e) Create new classes of shares or reorganize, consolidate, subdivide or otherwise change its outstanding shares or alter the rights, privileges, restrictions and conditions of any share of the corporation;

(f) Change the number of directors, unless the existing Articles permit the directors to specify the number of directors within the minimum and maximum number specified in the Articles;

(g) Appoint or change the corporation's auditor;

(h) Sell, lease or otherwise dispose of the assets or substantially all of the assets of the corporation; and

(i) Initiate any action, undertaking, or agreement which requires the approval of the shareholders as otherwise specified.

11. OTHER MATTERS REQUIRING SHAREHOLDER APPROVAL

Without Shareholder approval neither the Corporation nor the Subsidiaries shall:

(a) Enter into any retail business, including retailing electricity other than as authorized under Paragraph 3(a).

(b) Change the compensation to be paid to Directors or provide any financial assistance, whether by loan, guarantee, or otherwise to any Director or Officer other than financial assistance or loans to Directors or Officers who are also employees of the Corporation or the Subsidiaries as part of a comprehensive employee benefit package.

(c) Expand the service area for distributing electricity beyond the boundaries of the City of Orillia.

(d) Issue, or enter into any agreement to issue, any shares of any class, or any securities convertible into shares of any class, of the Corporation or the Subsidiaries.

(e) Incur expenditures, make acquisitions, dispose of assets of the Corporation or the Subsidiaries, enter into strategic alliances or joint ventures which would involve expenditures or would involve an amount in an aggregate value equal to 25% or greater of the consolidated book value of the consolidated assets of the Corporation, as reflected in the Corporation's most recent audited financial statement.

(f) Enter into any agreement, commitment or investment that provides recourse to the assets of the Corporation or the Subsidiaries or creates any encumbrance, lien, security interest or recourse (hereinafter collectively referred to as "Liens") in favour of any third party in such assets in priority to the Shareholder other than:

(1) Liens securing purchase money obligations incurred in the ordinary course of business (other than in relation to the borrowing of money) if the aggregate principal amount of such obligations does not exceed $1,000,000.00 at any time in total for the Corporation and the Subsidiaries.

(2) Liens securing credit facilities created or incurred for the purpose of providing operating financing for day-to-day working capital requirements and liens securing trade debts or other liabilities incurred in the ordinary course of business (other than in relation to the borrowing of money) if the aggregate principal amount of any such obligations does not exceed in total for the Corporation and the Subsidiaries the equivalent of two months consolidated net expenses as reflected in the Corporation's most recent audited consolidated Financial Statements. Consolidated net expenses are defined to be the sum of consolidated cost of power distributed plus consolidated operating expenditures plus consolidated interest on long term debt plus consolidated income taxes.

(3) Liens securing credit facilities required by Distco to satisfy the Independent Market Operator's requirements for the acquisition of power except to the extent that such liens are required to secure past or existing defaults.

(4) Liens held by any government authority pursuant to law or that relate to obligations of the Corporation that are not due or delinquent.

(g) Invest in funds in publicly-traded securities other than those eligible investments as prescribed by Ontario Regulation 438/97 made under the Municipal Act of Ontario as amended or replaced from time to time.

12. <u>REPORTING</u>

The Board of Directors of the Corporation shall submit progress reports on its activities, and those of the Subsidiaries, semi-annually to the Council of the Shareholder. The Board may from time to time report to Council on major business developments or materially adverse results as the Board, in its discretion, considers appropriate, and such reports received may be considered by the Shareholder at an in-camera meeting of Council.

13. <u>CONFIDENTIALITY</u>

The Shareholder and the Directors and Officers of the Corporation and the Subsidiaries (each a "receiving party") will ensure that no confidential information of the Shareholder or the Corporation or the Subsidiaries is disclosed or otherwise made available to any person, except to the extent that:

(a) Disclosure to a receiving party's employees or agents is necessary for the performance of any receiving party's duties and obligations under this or any other Shareholder Declaration;

(b) Disclosure is required in the course of judicial proceedings or pursuant to law; or

(c) The confidential information becomes part of the public domain (other than through unauthorized disclosure by the receiving party).

14. <u>ENVIRONMENTAL MATTERS</u>

The Board of Directors of the Corporation shall manage the Corporation and the Subsidiaries in a safe and environmentally responsible manner having regard to any recommendations made by the City of Orillia's Environmental Advisory Committee from time to time.

15. <u>AMENDMENTS</u>

This Shareholder Declaration may be revised from time to time as circumstances require and the Shareholder will consult with the Board of Directors of the Corporation prior to completing any revisions and will promptly provide the Board with copies of such revisions.

DATED AT Orillia, Ontario, this day of , 2000.

THE CORPORATION OF THE
CITY OF ORILLIA

per: ______________________
Name:
Title:

per: ______________________
Name:
Title:

SCHEDULE "C" - HOLDCO ASSETS AND HOLDCO LIABILITIES

HOLDCO ASSETS

$50,000.00 cash.

Participation interest in the Upper Canada Energy Alliance.

HOLDCO LIABILITIES

NIL

The determination of the purchase price and the transfer of Holdco Assets is illustrated in Schedule "C-1" hereto.

SCHEDULE "C-1"
HOLDCO FINANCIAL SCHEDULE ILLUSTRATING TRANSFER

ASSETS	
CURRENT ASSETS	
Cash and short term investments	50,000
	50,000
TOTAL PURCHASE PRICE	$50,000
LIABILITIES ASSUMED	
CURRENT LIABILITIES	
Accounts payable and accrued liabilities	Nil
	Nil
TOTAL LIABILITIES ASSUMED	Nil
NET TRANSFER	$50,000
CONSIDERATION FOR TRANSFER	
DEBT & EQUITY	
Promissory Note issued to City of Orillia	Nil
Common Shares issued to City of Orillia	50,000
	50,000

SCHEDULE "D" - DISTCO ASSETS AND DISTCO LIABILITIES

DISTCO ASSETS

All assets, interests, property, rights and undertaking, registered or unregistered, secured or unsecured, other than the Excluded Assets, the Holdco Assets and the Genco Assets, of the Commission and of the City held or used by either of them as at the Effective Date which relate to or have been used in connection with the distribution of electricity including, without limitation, the distribution system of the Commission and the assets listed hereunder.

1. Real Property Interests

   All lands, premises, freehold and leasehold property, interest, easements, rights-of-way, licences and rights to use or occupy real property whether registered or unregistered, liens, mortgages, charges, agreements, notice of agreements, debentures and security interests which create an interest in land and all other rights or interest therein, and fixtures thereon, which relate to or have been used in connection with the distribution of electricity by the Commission. For greater certainty the freehold interest in any lands owned by the City and used by the Commission for easements or rights-of-way are excluded except to the extent of such easements or rights-of-way.

2. Plant, Building, Fixtures

   All plant, buildings, structures, erections, improvements, appurtenances and fixtures (including fixed machinery and fixed equipment), terminal station, substations, transformers, vaults, sub-transmission lines, distribution lines, conduits, ducts, pipes, wires, rods, cables, fibres and other apparatus, devices, appliances and equipment, materials, works, poles, pipelines and fittings, meters, wherever situate including, without limitation, those situate on any of the lands, premises, leaseholds, easements, rights-of-way or interests whether registered or unregistered described in Paragraph 1 above or forming part thereof or otherwise, or located on property owned by the Commission, or the City, private property or public property, which relate to or have been used in connection with the distribution of electricity by the Commission.

3. Machinery and Equipment

   All machinery and equipment, all vehicles including, without limitation, trailers and related vehicle equipment, all goods and chattels and other personal property, tools, handling equipment, furniture, furnishings and accessories which relate to or have been used in connection with the distribution of electricity by the Commission.

4. Computer Hardware and Software

   All computer hardware and software, including, without limitation, system control and supervisory equipment (SCADA), all computer monitoring equipment and all rights under licences and other agreements or instruments relating to the distribution business of the Commission.

5. Accounts Receivable

   All accounts receivable of the Commission including, without limitation, all customer and trade accounts, notes receivable, book debts and other debts due or accruing to the Commission and the benefit of all security and security deposits for such accounts and debts, which relate to or have been used in connection with the distribution of electricity by the Commission.

6. Cash and Securities

   Except as specified in Schedules "C" and "E" hereto, all cash balances and short term debt instruments held by the Commission.

7. Contracts, Rights

The full benefit of all franchise, licence or management agreements and all other contracts, commitments, rights, choses in action, benefits, arrangements, understandings and agreements, written or oral, to which the City or the Commission is a party relating to the distribution business of the Commission including, without limitation the following:

(a) all written or oral contracts, agreements, commitments, undertakings, rights and arrangements;

(b) all forward commitments to the Commission for supplies or materials entered into in the usual and ordinary course of business whether or not there are any written contracts with respect thereto;

(c) all collective agreements and contracts of employment;

(d) Upper Canada Energy Alliance Aggregation Agreement and Settlement Services Agreement as well as limited partnership interest in EnerConnect.

8. Goodwill

The goodwill of the Commission relating to the distribution of electricity including, without limiting the generality of the foregoing:

(a) the exclusive right to represent itself as carrying on the distribution business in continuation of and in succession to the Commission and the right to use any words indicating that its business is so carried on; and

(b) all records of sales, customers lists, customer data and supplier lists of or used by the Commission, which relate to or have been used in connection with the distribution of electricity by the Commission.

9. Licences and Permits

The full benefit of all licences, registrations, permits, consents, quotas, approvals, certificates, and other authorizations including, without limitation, the following:

(a) the Transitional Distribution Licence (ED-1999-0084) issued to the Commission on April 1, 1999.

(b) Industry Canada Radio Licence.

10. Intellectual Property

All of the right, title, benefit and interest of the Commission in and to all registered trade marks, trade names, brand names, patents and copyrights, all unregistered trade marks, trade names and copyrights and all patent applications, trade mark registration applications and copyright registration applications, both domestic and foreign, owned or made by the Commission which relate to or have been used in connection with the distribution of electricity by the Commission.

11. Know How

All patents, plans, designs, research data, copyrights, trade secrets and other proprietary know-how, processes, drawings, technology, unpatented blueprints, flow-sheets, equipment and parts lists and descriptions and related instructions, manuals, data, records and procedures relating to the distribution business of the Commission and any and all data owned or used by the Commission, and all licences, agreements and other contracts and commitments relating to any of the foregoing which relate to or have been used in connection with the distribution of electricity by the Commission.

12. Prepaid Expenses

All pre-paid expenses and deposits relating to the distribution business of the Commission the benefit of which will accrue to Distco.

13. Warranties

The full benefit of all warranties and warranty rights (implied, express or otherwise) against manufacturers, suppliers or sellers which apply to any of the Distco Assets and the net realizable value of any warranty claims relating to the Distco Assets outstanding as of the Effective Date.

14. Insurance Policies

The full benefit of all policies of insurance of the Commission relating to the Distco Assets and the distribution business of the Commission.

15. Records

All personnel records, inspection records and all other records, books, documents and data bases relating to Distco Employees, the Distco Liabilities and the Distco Assets as are in the possession or under the control of the Commission; and

DISTCO LIABILITIES

1. All of the debts, liabilities and obligations of the Commission or the City, including any contingent liabilities, related to, incurred or assumed by either of them as of the Effective Date in connection with the distribution of electricity, the distribution system of the Commission and the Distco Assets including, without limitation, all environmental reclamation and decommissioning liabilities of the Commission or the City.

The determination of the purchase price and the transfer of the Distco Assets and Distco Liabilities is illustrated in Schedule "D-1" hereto.

SCHEDULE "D-1"
DISTCO FINANCIAL SCHEDULE ILLUSTRATING TRANSFER

ASSETS	
PROPERTY AND EQUIPMENT	
Property and equipment	14,814,000
CURRENT ASSETS	
Cash and short term investments	3,820,000
Accounts receivable	2,447,000
Unbilled revenue	543,000
Inventory	733,000
Other current assets	39,000
	7,582,000
OTHER ASSETS	
Development charges fund	246,000
	246,000
TOTAL PURCHASE PRICE	$22,642,000
LIABILITIES ASSUMED	
CURRENT LIABILITIES	
Accounts payable and accrued liabilities	2,339,000
	2,339,000
OTHER LIABILITIES	
Customer deposits	533,000
Development charges liability	246,000
	779,000
TOTAL LIABILITIES ASSUMED	$3,118,000
NET TRANSFER	$19,524,000
CONSIDERATION FOR TRANSFER	
DEBT & EQUITY	
Promissory Note issued to City of Orillia	9,762,000
Common Shares issued to City of Orillia	9,762,000
	19,524,000

SCHEDULE "D-2"
DISTCO PROMISSORY NOTE TERMS

1. **Principal Amount**

   $9,762,000.00.

2. **Interest Rate**

   7.5% per annum to December 31, 2005 and thereafter the interest rate will be changed for each subsequent 5 year period to be equal to 2% plus the annual rate paid by the Royal Bank of Canada (RBC) as set by the RBC head office in Toronto on December 31st of the year immediately preceding the commencement of each 5 year period on 270 day term deposits exceeding $8,000,000.00 (such $8,000,000.00 amount to be adjusted from time to time after December 31, 2000 to reflect the impact of inflation as measured by the Consumer Price Index). For greater certainty on October 11, 2000 the rate paid by RBC on a 270 day term deposit for $8,000,000.00 was 5.5%.

3. **Payment of Interest**

   Payments of interest shall be quarterly on the last days of March, June, September and December in each year. Interest shall commence to accrue on the date that the initial Performance Based Regulation rates for Distco become effective, and the first payment of interest shall become due on the first quarterly payment date next following the date that interest commences.

4. **Due Date**

   The due date is December 31, 2030. Distco shall not have the right to prepay the principal in whole or in part.

5. **Prepayment of Principal At Option of the City**

   The City, at its option, and upon giving to Distco at least 6 months written notice may require the prepayment of up to 20% of the original principal amount of the Promissory Note on March 31st in any calendar year.

6. **Acceleration on Default**

   In the event that Distco defaults in making any payments due under this Note and such default not having been corrected within 30 days after the City having given written notice to Distco of such default, then the City may demand immediate payment of all principal and interest due under the Promissory Note.

SCHEDULE "E" - GENCO ASSETS AND GENCO LIABILITIES

GENCO ASSETS

All assets, interests, property, rights and undertaking, registered or unregistered, secured or unsecured, other than the Excluded Assets, the Holdco Assets and the Distco Assets, of the Commission and of the City held or used by either of them as at the Effective Date which relate to or have been used in connection with the generation of electricity and other business activities carried on by the Commission including, without limitation, the assets listed hereunder.

1. Real Property Interests

   Except as specified in Schedule "D" hereto, all lands, premises, freehold and leasehold property, interest, easements, rights-of-way, licences and rights to use or occupy real property whether registered or unregistered, liens, mortgages, charges, agreements, notice of agreements, debentures and security interests which create an interest in land and all other rights or interest therein, and fixtures thereon, which relate to or have been used in connection with the generation of electricity and other business activities carried on by the Commission. For greater certainty the freehold, interest in any lands owned by the City and used by the Commission for easements or rights-of-way are excluded except to the extent of such easements or rights-of-way.

2. Plant, Building, Fixtures

   Except as specified in Schedule "D" hereto, all plant, buildings, structures, erections, improvements, appurtenances and fixtures (including fixed machinery and fixed equipment), the Swift, Minden and Matthias hydraulic generating stations, diesel generating plant, sub-transmission lines and, without limitation, all plant, buildings and fixtures situate on any of the lands, premises, leaseholds, easements, rights-of-way or interests whether registered or unregistered described in Paragraph 1 above or forming part thereof or otherwise, or located on property owned by the Commission, or the City, private property or public property, which relate to or have been used in connection with the generation of electricity and other business activities carried on by the Commission.

3. Machinery and Equipment

   Except as specified in Schedule "D" hereto, all machinery and equipment, all vehicles including, without limitation, trailers and related vehicle equipment, all goods and chattels and other personal property, tools, handling equipment, furniture, furnishings and accessories, which relate to or have been used in connection with the generation of electricity and other business activities carried on by the Commission.

4. Computer Hardware and Software

   Except as specified in Schedule "D" hereto, all computer hardware and software, including, without limitation, all computer monitoring equipment and all rights under licences and other agreements or instruments relating to the generation business and other business activities carried on by the Commission.

5. Broadband Telecommunications Infrastructure and Equipment

   All such equipment which relate to or have been used in connection with the broadband telecommunications business activities carried on by the Commission.

6. Accounts Receivable

   Except as specified in Schedule "D" hereto, all accounts receivable of the Commission including, without limitation, all customer and trade accounts, notes receivable, book debts and other debts due or accruing to the Commission and the benefit of all security and security deposits for such accounts and debts, which relate to or have been used in connection with the generation of electricity and other business activities carried on by the Commission.

7. Cash and Securities

Except as specified in Schedules "C" and "D" hereto, all cash balances and short term debt instruments held by the Commission.

8. Contracts, Rights

Except as specified in Schedule "D"hereto, the full benefit of all franchise, licence or management agreements and all other contracts, commitments, rights, choses in action, benefits, arrangements, understandings and agreements, written or oral, to which the City or the Commission is a party relating to the generation business and other business activities carried on by the Commission including, without limitation the following:

(a) all written or oral contracts, agreements, commitments, undertakings, rights and arrangements;

(b) all forward commitments to the Commission for supplies or materials entered into in the usual and ordinary course of business whether or not there are any written contracts with respect thereto;

(c) all collective agreements and contracts of employment;

(d) any agreements and rights pertaining to undeveloped hydraulic generation sites;

(e) any agreements with the former Ontario Hydro for the wheeling and supply of power from the Swift and Minden Power Plants to Orillia.

9. Goodwill

Except as specified in Schedule "D" hereto, the goodwill of the Commission including, without limiting the generality of the foregoing:

(a) the exclusive right to represent itself as carrying on the generation business and other business activities in continuation of and in succession to the Commission and the right to use any words indicating that its business is so carried on; and

(b) all records of sales, customers lists, customer data and supplier lists of or used by the Commission, which relate to or have been used in connection with the generation of electricity and other business activities carried on by the Commission.

10. Licences and Permits

Except as specified in Schedule "D" hereto, the full benefit of all licences, registrations, permits, consents, quotas, approvals, certificates, and other authorizations including, without limitation, the following:

(a) The Transitional Generation Licence (EG-1999-0395) issued to the Commission on April 1, 1999.

(b) Industry Canada Radio Licence.

11. Intellectual Property

Except as specified in Schedule "D" hereto, all of the right, title, benefit and interest of the Commission in and to all registered trade marks, trade names, brand names, patents and copyrights, all unregistered trade marks, trade names and copyrights and all patent applications, trade mark registration applications and copyright registration applications, both domestic and foreign, owned or made by the Commission which relate to or have been used in connection with the generation of electricity and other business activities carried on by the Commission.

12. Know How

Except as specified in Schedule "D" hereto, all patents, plans, designs, research data, copyrights, trade secrets and other proprietary know-how, processes, drawings, technology, unpatented blueprints, flow-sheets, equipment and parts lists and descriptions and related instructions, manuals, data, records and procedures relating to the generation business of the Commission and any and all data owned or used by the Commission, and all licences, agreements and other contracts and commitments relating to any of the foregoing which relate to or have been used in connection with the generation of electricity and other business activities carried on by the Commission.

13. Prepaid Expenses

Except as specified in Schedule "D" hereto, all pre-paid expenses and deposits relating to the generation business and other business activities carried on by the Commission, the benefit of which will accrue to Genco.

14. Warranties

The full benefit of all warranties and warranty rights (implied, express or otherwise) against manufacturers, suppliers or sellers which apply to any of the Genco Assets and the net realizable value of any warranty claims relating to the Genco Assets outstanding as of the Effective Date.

15. Insurance Policies

Except as specified in Schedule "D" hereto, the full benefit of all policies of insurance of the Commission relating to the Genco Assets and the generation business and other business activities carried on by the Commission.

16. Records

All personnel records, inspection records and all other records, books, documents and data bases relating to Genco Employees, the Genco Liabilities and the Genco Assets as are in the possession or under the control of the Commission.

GENCO LIABILITIES

1. Except as specified in Schedule "D" hereto, all of the debts, liabilities and obligations of the Commission or the City, including any contingent liabilities, related to, incurred or assumed by either of them as of the Effective Date in connection with the generation of electricity and other business activities carried on by the Commission, and the Genco Assets including, without limitation, all environmental reclamation and decommissioning liabilities of the Commission or the City.

The determination of the purchase price and the transfer of the Genco Assets and Genco Liabilities is illustrated in Schedule "E-1" hereto.

SCHEDULE "E-1"
GENCO FINANCIAL SCHEDULE ILLUSTRATING TRANSFER

ASSETS	
PROPERTY AND EQUIPMENT	
Property and equipment	6,265,000
CURRENT ASSETS	
Cash and short term investments	1,000,000
Inventory	66,000
	1,066,000
OTHER ASSETS	
Insurance contingency investments fund	1,886,000
	1,886,000
TOTAL PURCHASE PRICE	**$9,217,000**
LIABILITIES ASSUMED	
CURRENT LIABILITIES	
Accounts payable and accrued liabilities	139,000
	139,000
OTHER LIABILITIES	
Reserve for insurance contingency	1,886,000
	1,886,000
TOTAL LIABILITIES ASSUMED	**$2,025,000**
NET TRANSFER	**$7,192,000**
CONSIDERATION FOR TRANSFER	
DEBT & EQUITY	
Promissory Note issued to City of Orillia	5,034,000
Common Shares issued to City of Orillia	2,158,000
	7,192,000

SCHEDULE "E-2"
GENCO PROMISSORY NOTE TERMS

1. Principal Amount

   $5,034,000.00.

2. Interest Rate

   7.5% per annum to December 31, 2005 and thereafter the interest rate will be changed for each subsequent 5 year period to be equal to 2% plus the annual rate paid by the Royal Bank of Canada (RBC) as set by the RBC head office in Toronto on December 31st of the year immediately preceding the commencement of each 5 year period on 270 day term deposits exceeding $8,000,000.00 (such $8,000,000.00 amount to be adjusted from time to time after December 31, 2000 to reflect the impact of inflation as measured by the Consumer Price Index). For greater certainty on October 11, 2000 the rate paid by RBC on a 270 day term deposit for $8,000,000.00 was 5.5%.

3. Payment of Interest

   Payments of interest shall be quarterly on the last days of March, June, September and December in each year commencing 2001. Interest shall commence to accrue November 1, 2000, and the first payment of interest shall become due December 31, 2000 for the 2 month period.

4. Due Date

   The due date is December 31, 2030. Genco shall not have the right to prepay the principal in whole or in part.

5. Prepayment of Principal At Option of the City

   The City, at its option, and upon giving to Genco at least 6 months written notice may require the prepayment of up to 20% of the original principal amount of the Promissory Note on March 31st in any calendar year.

6. Acceleration on Default

   In the event that Genco defaults in making any payments due under this Note and such default not having been corrected within 30 days after the City having given written notice to Genco of such default then the City may demand immediate payment of all principal and interest due under the Promissory Note.

SCHEDULE "F" - EXCLUDED ASSETS AND EXCLUDED LIABILITIES

EXCLUDED ASSETS

NIL

EXCLUDED LIABILITIES

NIL

SCHEDULE "G"

DISTCO EMPLOYEES TRANSFERRED AND COLLECTIVE AGREEMENTS

EMPLOYEES TRANSFERRED TO DISTCO

ANSLEY, SHERRY
ARORA, HARBANS
BUDD, BRENDA
COLE, NEALE
DOYLE, THERESA
EVANS, CHRIS
FARRUGIA, DONNA
FORTIN, ROGER
GATEHOUSE, WOODROW
GOLUB, NIKO
HURLEY, PATRICK
LANGMAN, DEAN
LEE, JOSEPH
MARK, ROBERT
MARTIN, MARY ANNE
MATTHEWS, MATT
MATTINSON, JOHN
MCMILLAN, MAURICE
MCSORLEY, ALANNA
MISTAL, PATRICK
MORRIS, DAVID
MURRAY, LAWRENCE
MURRAY, GUY
ORSER, PAUL
REYNOLDS, MARY LOU
STACKHOUSE, WILLIAM
TAYLOR, SANDRA
THAXTER, SHELLEY
THOMPSON, JANEY
TUORILA, HELEN
UDELL, RITCHIE
WATSON, RIC
WESTGARTH, DONALD
WONCH, DARYL
WRIGHT, SUSAN
WRIGHT, ROBERT
ZWIERS, JEFFREY

COLLECTIVE AGREEMENTS

Collective Agreements for employees transferred to Distco

IBEW, Local 636 - Outside Employees Union Agreement - from September 1, 1999 to August 31, 2001.

IBEW, Local 636 - Inside Employees Union Agreement - from September 1, 1999 to August 31, 2001.

SCHEDULE "H"

GENCO EMPLOYEES TRANSFERRED AND COLLECTIVE AGREEMENTS

EMPLOYEES TRANSFERRED TO GENCO

BEERS, MATT
BURKE, STEVE
BURNIE, BRIAN
FENWICK, DON
HAWKINS, DAVID
LISCOMBE, ROBERT
O'BRIEN, WILLIAM
VOLLICK, BRUCE
WATTS, DANNY
YEATMAN, MALCOLM

COLLECTIVE AGREEMENTS

Collective Agreements for employees transferred to Genco

IBEW, Local 636 - Outside Employees Union Agreement - from September 1, 1999 to August 31, 2001.

BY-LAW NUMBER 2000-155 OF THE CITY OF ORILLIA

A BY-LAW TO AMEND BY-LAW NUMBER 2000-144

WHEREAS Council of the Corporation of the City of Orillia passed By-law Number 2000-144 on October 16, 2000;

AND WHEREAS Section 4.10 of the said By-law authorized an exchange of shares between Holdco and the City;

AND WHEREAS such exchange of shares should include those shares of Distco and Genco issued to the City pursuant to Section 2.02 of the said By-law.

NOW THEREFORE THE COUNCIL OF THE CORPORATION OF THE CITY OF ORILLIA HEREBY ENACTS AS FOLLOWS:

1. WHENEVER used in this By-law, including the Recitals, unless the context otherwise requires the words and terms set out in Schedule "A" of By-law Number 2000-144 have the respective meanings ascribed to them in the said Schedule "A".

2. THAT Section 4.10 of By-law Number 2000-144 is hereby amended to read as follows:

"4.10 Transfers of Shares

As the City desires to continue the distribution, retailing and generation of electricity through Holdco, Distco and Genco, all of the common shares of Distco and Genco issued to the City pursuant to Sections 2.02, 4.03 and 4.04 of this By-law shall be transferred to Holdco by the City as of the Effective Date in exchange for the allotment and issuance by Holdco to the City of an additional 1,000 fully paid and non-assessable common shares of Holdco."

3. THIS By-law is passed pursuant to Subsection 145(1) of the Electricity Act.

BY-LAW read a first, second and third time and finally passed this 30th day of October, A.D. 2000.

CERTIFIED TO BE A TRUE AND CORRECT COPY OF BY-LAW NUMBER 2000-155
CITY CLERK
DATE Oct 31/00

M Buchanan
ACTING HEAD OF COUNCIL

CLERK

Ontario Energy Board (Board Staff) INTERROGATORY #2

Interrogatory:

Ref: Exh A/T2/Sch1/p.2

The proposed transaction is expected to result in reductions in operating, maintenance and administration (OM&A) and capital costs. Table 1 sets out the applicants' projected cost savings on a yearly basis for ten years following the closing of the transaction. The projected savings are shown as the difference in costs between the status quo forecast, i.e., in the absence of the transaction and Hydro One's forecast, post transaction.

a) Please confirm whether Year 1 in the table represents the year 2016 or 2017.

b) Please identify the specific areas of the distribution business where the projected cost savings are expected to be generated as a result of the proposed transaction.

c) Please provide a breakdown of the costs by the identified business areas in b) which explains the difference between the status quo forecast and Hydro One's forecast.

d) Please confirm whether the projected savings include or exclude the incremental transaction and integration costs identified in the application. If the projected savings do not include the transaction and integration costs, please provide an updated forecast that includes these costs.

e) Please explain what assumptions have been made by the applicants with respect to the expected cost savings.

f) Please identify risks that could negatively impact the projected cost savings, setting out the projected savings if those risks materialize.

Response:

a) Year 1 in the table represents a 12 month period post-closing of the transaction. This period is assumed to most closely align with calendar year 2017.

b) Anticipated on-going cost savings are attributed to the individual business areas as shown in Table 1 below:

Table 1

Business Area	**Annual Range ($ million)**	
	Low	**High**
Administration		
Management/Corporate Governance	0.9	1.1
Financial/Regulatory	0.3	0.3
Other	0.1	0.6
	1.3	**2.0**
Back Office		
Customer Service	0.4	0.6
Information Technology/Other	0.4	0.4
	0.8	**1.1**
Distribution Operations	0.7	0.8
Total OM&A	**2.8**	**3.9**
Total Capital (including reprioritization)	**0.5**	**0.7**

c) Refer to part b) above.

d) The projected savings exclude incremental transaction and integration costs as these costs are incurred by the shareholder to complete the transaction and will not be part of the ongoing costs incurred to operate the OPDC business. Table 1, represents Hydro One's forecast ongoing costs to serve the customers of OPDC.

If the question is requesting an update to Hydro One's forecast transaction and integration costs, at this point in time they are consistent with the prefiled evidence. Hydro One's incremental transaction costs are estimated to be $3 million, while integration costs are estimated to be between $5 million and $6 million. The following table provides a breakdown of these costs that are in addition to those found in Exhibit A, Tab 2, Schedule 1, Table 1.

Table 2

Hydro One Forecast - $M Incremental Transaction and Integration Costs	Closing	Year 1	Year 2
Part III.1 Tax on Excessive Eligible Dividend Designations	2.5		
Advisory Fees	0.3		
Regulatory Approval / Land Transfer Tax	0.1		
Total Transaction Costs	**2.9**		
Total Integration (Customers, Assets, Employees)		**5.2**	**0.4**

e) Hydro One wishes to emphasize that forecast savings are not based on a bottom up forecast approach by business area. Rather, the overall expected savings described in Exhibit A, Tab 2, Schedule 1 Page 1 at Line 25 (i.e., $4.5 million per year by Year 10) are based on a comparison completed by Hydro One of OPDC's operations as a stand-alone distribution utility, to OPDC expected operations once it is integrated within Hydro One. The Hydro One forecast is an evaluation of the incremental cost of operating and maintaining a fully integrated OPDC service territory - it is not premised on the build-up of OPDC's historic costs. Please refer to Attachment 1 of this response for the detailed calculation of Projected Savings summarized in Exhibit A, Tab 2, Schedule 1, Table 1.

Hydro One's integration projections are based on its overall, provincial distribution operations which utilize an Asset Risk Assessment (ARA) process. The Hydro One ARA process encompasses the assessment of a multitude of applicable asset categories. In the OPDC integration case, Hydro One examined the functions outlined below:

- Vegetation Management
- Lines Maintenance and Refurbishment
- Demand Work
- Wood Pole Replacement
- Stations
- Environment
- Other Sustainment
- Customer Connections / Upgrades
- System Reinforcement
- Distributed Generation
- Other Development

Field assessment and visual inspections and evaluations were completed and asset information was collected on existing OPDC assets such as asset age, number of assets, asset condition, etc. Utilizing this data, renewal and maintenance costing based on Hydro One's strategies for all Hydro One assets was applied to determine asset needs going forward for maintenance and capital funding. This process was used to provide an estimate of the overall level of spending required to serve the existing OPDC service territory, as provided in Hydro One's pre-filed evidence referenced in Exhibit A, Tab 2, Schedule 1. The aggregate spend was then compared to the OPDC's forecast aggregate spend over the same 10-year period to project the net annual savings provided.

Hydro One's ARA process is further described in Exhibit D1, Tab 2, Schedule 1 of EB-2009-0096 and Exhibit A, Tab 17, Schedule 17 of EB-2013-0416. The ARA process is relied upon by Hydro One for its ongoing operations throughout the province in respect of developing operating and maintenance cost expectations and schedules for all existing assets.

f) Factors that may affect the achievement of the expected efficiencies include:

- Unknown environmental concerns such as the presence or release of hazardous or other harmful substances that could lead to necessary actions such as investigating, controlling and remediating the effects of these substances
- Risks associated with the integration of information technology infrastructure
- Modifications to the distribution system, including necessary investments to support renewable generation activities
- Risk associated with procurement needs (e.g., foreign exchange rates)
- Unforeseen changes in law, changes in provincial energy policy and/or regulatory policy changes that may result in increased spending requirements
- Risks of natural and other unexpected occurrences (e.g., natural disasters, or some other catastrophic event).

Hydro One has not performed a detailed analysis of the impact on the projected savings should any of the identified risks materialize.

Attachment 1
Exhibit A, Tab 1, Schedule 2, Table 1 Calculation Assumptions

General

- This document supplements the assumptions embedded within the Table 1 Excel file provided as Exhibit I, Tab 1, Schedule 2, Attachment 2.
- Year 1 in Table 1 represents a 12 month period post-closing of the transaction. This period is assumed to most closely align with calendar year 2017.
- Inflation factors
    - OM&A ~2% per annum
    - Capital ~3% per annum

Status Quo Forecast

- Status Quo Forecast represents the continued operation of OPDC as a stand-alone utility (i.e., no transaction scenario)

OM&A

- Based on the 2015 OPDC audited Financial Statement's OM&A, adjusted to exclude a $250k charitable donation
- The Adjusted 2015 OM&A amount is extrapolated over the 10 year deferral period and escalated for inflation

Capital

- Based on the average spend of OPDC's 2017-21 Capital Plan Strategy, as is, without assessment of the individual plan components, then that average spend is applied over the 10 year deferral period, adjusted for inflation.

Hydro One Forecast

- Hydro One Forecast represents the incremental cost of Hydro One operating and maintaining an integrated OPDC service territory
- Customer growth based on Hydro One's forecast: ~1% per annum
- Full operational integration occurs 7 months post financial close (i.e., part way through Year 1)
- OPDC Operations Centre leased for three years
- Costs are primarily captured in the broad categories of operations, customer care and capital expenditures

Table 1

$M	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
OM&A										
Status Quo Forecast	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.8
Hydro One Forecast	4.1	2.1	2.0	1.7	1.7	1.7	1.8	1.8	1.9	1.9
Projected Savings	0.7	2.8	2.9	3.4	3.5	3.6	3.6	3.7	3.8	3.9
Capital										
Status Quo Forecast	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.6
Hydro One Forecast	3.6	2.3	2.4	2.3	2.4	2.5	2.6	2.7	2.9	3.0
Projected Savings	(0.9)	0.5	0.5	0.7	0.7	0.7	0.7	0.7	0.6	0.6

Hydro One Forecast **OPDC Post-Hydro One MAAD**

	2017 **Year 1**	2018 **Year 2**	2019 **Year 3**	2020 **Year 4**	2021 **Year 5**	2022 **Year 6**	2023 **Year 7**	2024 **Year 8**	2025 **Year 9**	2026 **Year 10**
OM&A Expenditures										
Operations	318	790	815	840	866	892	919	947	976	1,005
Customer Care	302	739	735	747	757	768	779	790	801	813
Other Costs	661	128	77	79	81	82	84	86	87	89
Lease of Orillia HQ	397	404	411							
Stand Alone LDC (7 mths)	2,422									
Total OM&A	**4,100**	**2,062**	**2,039**	**1,666**	**1,703**	**1,742**	**1,781**	**1,822**	**1,865**	**1,907**
Capital Expenditures										
Capital	858	2,327	2,411	2,295	2,387	2,483	2,582	2,686	2,934	2,962
Stand Alone LDC (7 mths)	2,752									
Total Operations Capital	**3,610**	**2,327**	**2,411**	**2,295**	**2,387**	**2,483**	**2,582**	**2,686**	**2,934**	**2,962**

Status Quo OM&A Derivation

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total OM&A per Financial Statements	4,849											
Less Non-recurring Donation	(250)											
Adjusted 2015 Actuals	4,599											
Escalation assumptions		1.2%	2.1%	2.6%	2.3%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.0%
			Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
Status Quo OM&A Forecast			4,752	4,875	4,988	5,092	5,199	5,308	5,420	5,534	5,650	5,763

Status Quo Capital Derivation

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capital										
Land & Buildings	16,000	16,000	16,000	16,000	16,000					
Subtransmission	365,000	321,000	254,000	254,000	82,000					
Substations	796,000	1,300,000	0	100,000	500,000					
Overhead	837,000	1,641,000	2,111,000	1,215,000	1,336,000					
Underground	123,000	569,000	123,000	123,000	123,000					
Transformers and Meters	88,000	108,000	98,000	88,000	88,000					
Computer Hardware & Software	105,000	80,000	35,000	35,000	35,000					
Office Equipment & Furniture	10,000	10,000	10,000	10,000	10,000					
Vehicles	390,000	70,000	350,000	430,000	75,000					
Tools & Equipment	40,000	40,000	40,000	40,000	40,000					
Total Capital	2,770,000	4,155,000	3,037,000	2,311,000	2,305,000					

Total Capital Expenditures: 2017 - 2021	14,578
5-Year Average	2,916

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Escalation assumptions	2.5%	3.1%	3.2%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.0%

	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
Status Quo Capital Forecast	2,740	2,825	2,916	3,006	3,099	3,195	3,294	3,396	3,502	3,607

Ontario Energy Board (Board Staff) INTERROGATORY #3

Interrogatory:

Ref: Exh A/T2/Sch1/pp.15-16

The application states that Hydro One's incremental transaction costs are estimated to be $3 million and integration costs are estimated to be between $5-6 million. According to the evidence, the premium that Hydro One is paying for this acquisition is approximately $18.8 million. The application indicates that incremental transaction costs and the premium will not be included in Hydro One's revenue requirement, and thus will not be funded by ratepayers.

a) Please provide a breakdown of the incremental transaction and integration costs referred to in the application, indicating the year/s in which these costs are expected to be incurred.

b) Please state how Hydro One will ensure that these costs will not be included in its ratepayer funded revenue requirement.

c) Please identify any factors that may affect the recovery of costs associated with the proposed transaction.

Response:

a) A breakdown of the incremental transaction and integration costs is provided in the response to Exhibit I, Tab 1, Schedule 2d).

b) Hydro One has not and will not forecast any incremental transaction or integration costs in any business plan requesting approval of a revenue requirement which will be used to form distribution rates. All revenue requirement applications filed by Hydro One are reviewed by the Ontario Energy Board to determine if costs are just and reasonable for both consumers and the utility.

c) Some of the factors that would impact the recovery of these costs include:
    - Not achieving anticipated productivity gains
    - Higher integration costs than estimated
    - Change in economic conditions (e.g. inflation, unemployment, impact on consumption)
    - Not having the application approved as requested.

Ontario Energy Board (Board Staff) INTERROGATORY #4

Interrogatory:

Ref: Exh A/T1/Sch1/p.1
Exh A/T2/Sch1/p.4

Orillia Power is requesting that its existing rate order, approved in the OEB's Decision and Order EB-2015-0024 be transferred to Hydro One Networks Inc. (Hydro One Networks) following the completion of the transaction. The application states that all Orillia Power tariffs will remain as approved in Orillia Power's existing rate order, with the exception of Specific Service Charges where Orillia Power customers using these services will be charged the rates approved for Hydro One Networks in rate order EB-2015-0079.

a) Please confirm whether Hydro One is seeking approval through this application for the proposed amendment to Orillia Power's Specific Service Charges as outlined in the application. If so:
   i. Please provide reasons for this proposed amendment, including why this change is being requested as part of this consolidation application.
   ii. Please describe the impact of this change on the Orillia Power customers using these services.
   iii. Please comment on whether the proposal to charge customers of Orillia Power using Hydro One Networks approved Specific Service Charges is considered an integral aspect of the consolidation, as referenced on page 11 of the *OEB's Handbook to Electricity Distributor and Transmitter Consolidations*.

b) For the rate riders in Orillia Power's existing rate order approved by the OEB which have an expiry date within the requested deferred rebasing period, please confirm whether any extension or amendment is being sought through this application and if so, provide details for each rate rider.

Response:

a) Yes, Hydro One is seeking approval to amend OPDC's Specific Service Charges ("SSCs") as shown in Attachment 9 of the Application, Page 11 of 13 of the proposed rate schedules.

i. There are multiple reasons for the proposed amendment.

Miscellaneous services are provided at a customer's request or as the result of a customer's action or inaction and impose costs on the distributor. In order to recover these costs from the directly affected party, following a user-pays principle, distributors charge Specific Service Charges ("SSCs") to the customer either at an OEB-approved rate (established using the OEB's 2006 Distribution Rate Handbook or by means of a rate order) or by using actual costs ("time and materials") of rendering the service.

At this time Hydro One is requesting that the Board approve the use for OPDC customers of Hydro One's SSCs as defined in rate order EB-2015-0079. Hydro One submits that this is the most cost-effective solution as the Hydro One billing system is designed to charge against only one set of SSCs. System modification costs and/or manual workaround costs would be incurred by Hydro One if the direction is to deviate from one set of charges. For instance, when the municipality street lights are registered in the Hydro One billing system, the system will automatically charge the municipality $0.17/month or $2.04 annually for each street light. Billing system modifications and/or manual workarounds would be required to avoid these charges. Additionally, call centre agents would require additional training to address the different charges for Orillia-specific customers and to answer any customer concerns regarding the disparities in the two sets of charges for the same rendered service.

It is important to note that many of the SSCs defined in the rate orders of both Hydro One and OPDC are set per Section 11 of the 2006 OEB Distribution Rate Handbook. The 2006 costs no longer reflect the true costs to render these services. On November 5, 2015, the OEB announced that it would be initiating a comprehensive policy review of miscellaneous rates and charges applied by electricity distributors for specific activities or services they provide to their customers[1]. In addition, Hydro One's Decision and Order for its last rate application[2], issued March 12, 2015, directed Hydro One to perform a study ("the Study") to determine the underlying costs of providing these services and to propose changes to the respective miscellaneous services. Hydro One will be providing the results of the Study and the resulting proposed changes to the SSCs in its upcoming distribution rate application. This may result in significant difference in SSCs between the two companies.

[1] EB-2015-0304
[2] EB-2013-0416

Hydro One understands that there is some hesitation in approving rates that are subject to change in the short-term but relies on the fact that the appropriateness of those rates will be subject to review by the OEB in its upcoming rates application. If/when the OEB does approve new SSCs for Hydro One, Hydro One would submit a new draft rate order for SSCs for the current OPDC service territory which would be reflected in the OPDC rate schedule that would remain throughout the deferral period.

ii. OPDC customers will continue to be billed charges that properly reflect costs to render these miscellaneous services that have been, and will continue to be, reviewed by the OEB.

iii. Hydro One does not propose that the SSC approval is considered an integral part of the Application. In so doing Hydro One would like to highlight that any necessary modifications, training, and other potential costs, that are required to continue to operate separate rate schedules for the two utilities would erode efficiencies associated with this consolidation.

b) Hydro One has reviewed OPDC's current approved rate riders and requests the following amendments to the proposed Rate Schedules as filed in Attachment 9 of the Application.

Current Rider Description	**Proposed Rider Description or Amendment**
Rate rider for application of tax changes (2016) – effective until April 30, 2017	Rate rider for application of tax changes – effective until the effective date of the next cost of service application
Rate Rider for Disposition of Account 1576 - effective until December 31, 2016 - Approved on an Interim Basis	Delete as Rider has expired

Attachment 1 to this interrogatory response provides the updated proposed Rate Schedules.

Hydro One Orillia

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXX X, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-XXXX

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	17.68
Rate Rider for Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	$	2.56
Rate Rider for Application of Tax Change – effective until the effective date of the next cost of service application	$	(0.08)
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Fixed Acquisition Rate Rider – in effect until the effective date of the next cost of service application	$	(0.18)
Distribution Volumetric Rate	$/kWh	0.0127
Low Voltage Service Rate	$/kWh	0.0006
Volumetric Acquisition Rate Rider – in effect until the effective date of the next cost of service application	$/kWh	(0.0001)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017 Applicable only for Non-Wholesale Market Participants	$/kWh	(0.0028)
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Retail Transmission Rate - Network Service Rate	$/kWh	0.0054
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0041

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Hydro One Orillia

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXX X, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-XXXX

ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

In addition to the charges specified on page 1 of this tariff of rates and charges, the following credits are to be applied to eligible residential customers.

APPLICATION

The application of the charges are in accordance with the Distribution System Code (Section 9) and subsection 79.2(4) of the Ontario Energy Board Act, 1998.

The application of these charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

In this class:

"Aboriginal person" includes a person who is a First Nations person, a Métis person or an Inuit person;
"account-holder" means a consumer who has an account with a distributor that falls within a residential-rate classification as specified in a rate order made by the Ontario Energy Board under section 78 of the Act, and who lives at the service address to which the account relates for at least six months in a year;
"electricity-intensive medical device" means an oxygen concentrator, a mechanical ventilator, or such other device as may be specified by the Ontario Energy Board;
"household" means the account-holder and any other people living at the accountholder's service address for at least six months in a year, including people other than the account-holder's spouse, children or other relatives;
"household income" means the combined annual after-tax income of all members of a household aged 16 or over;

MONTHLY RATES AND CHARGES

Class A

(a) account-holders with a household income of $28,000 or less living in a household of one or two persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of three persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of five persons; and
(d) account-holders with a household income of between $48,001 and $52,000 living in a household of seven or more persons;
but does not include account-holders in Class E.

OESP Credit	$	(30.00)

Class B

(a) account-holders with a household income of $28,000 or less living in a household of three persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of four persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of six persons;
but does not include account-holders in Class F.

OESP Credit	$	(34.00)

Class C

(a) account-holders with a household income of $28,000 or less living in a household of four persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of five persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of seven or more persons;
but does not include account-holders in Class G.

OESP Credit	$	(38.00)

Class D

(a) account-holders with a household income of $28,000 or less living in a household of five persons; and
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of six persons;
but does not include account-holders in Class H.

OESP Credit	$	(42.00)

Hydro One Orillia
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXX X, 2016
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-XXXX

ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

Class E

Class E comprises account-holders with a household income and household size described under Class A who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(45.00)

Class F

(a) account-holders with a household income of $28,000 or less living in a household of six or more persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of seven or more persons; or
(c) account-holders with a household income and household size described under Class B who also meet any of the following conditions:

i. the dwelling to which the account relates is heated primarily by electricity;
ii. the account-holder or any member of the account-holder's household is an Aboriginal person; or
iii. the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates

OESP Credit	$	(50.00)

Class G

Class G comprises account-holders with a household income and household size described under Class C who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(55.00)

Class H

Class H comprises account-holders with a household income and household size described under Class D who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person ; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(60.00)

Class I

Class I comprises account-holders with a household income and household size described under paragraphs (a) or (b) of Class F who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(75.00)

Hydro One Orillia

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXX X, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-XXXX

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	37.42
Rate Rider for Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	$	7.48
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Fixed Acquisition Rate Rider – in effect until the effective date of the next cost of service application	$	(0.37)
Distribution Volumetric Rate	$/kWh	0.0165
Low Voltage Service Rate	$/kWh	0.0006
Volumetric Acquisition Rate Rider – in effect until the effective date of the next cost of service application	$/kWh	(0.0002)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017 Applicable only for Non-Wholesale Market Participants	$/kWh	(0.0028)
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Rate Rider for Application of Tax Change – effective until the effective date of the next cost of service application	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0045
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Hydro One Orillia

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXX X, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-XXXX

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O.Reg.429/04. 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	340.60
Fixed Acquisition Rate Rider – in effect until the effective date of the next cost of service application	$	(3.41)
Distribution Volumetric Rate	$/kW	3.5825
Low Voltage Service Rate	$/kW	0.2230
Volumetric Acquisition Rate Rider – in effect until the effective date of the next cost of service application	$/kW	(0.0358)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017	$/kW	0.4856
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017 Applicable only for Non-Wholesale Market Participants	$/kW	(1.0338)
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017 Applicable only for Non-RPP Customers	$/kW	2.7738
Rate Rider for Application of Tax Change – effective until the effective date of the next cost of service application	$/kW	(0.0156)
Retail Transmission Rate - Network Service Rate	$/kW	1.9991
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5382

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Hydro One Orillia

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXX X, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-XXXX

STANDBY POWER SERVICE CLASSIFICATION

This classification applies to an account with load displacement facilities that contracts with the distributor to provide emergency standby power when its load displacement facilities are not in operation. The level of billing demand will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation such as nameplate rating of the load displacement facility. 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - APPROVED ON AN INTERIM BASIS

Distribution Volumetric Rate - $/kW of contracted amount	$/kW	1.0713

Hydro One Orillia
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	10.59
Distribution Volumetric Rate	$/kWh	0.0095
Low Voltage Service Rate	$/kWh	0.0006
	$/kWh	
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017 Applicable only for Non-Wholesale Market Participants	$/kWh	(0.0028)
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Rate Rider for Application of Tax Change – effective until the effective date of the next cost of service	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0045
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Hydro One Orillia

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXX X, 2016

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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are unmetered lighting load supplied to a sentinel light. 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.88
Distribution Volumetric Rate	$/kW	10.1477
Low Voltage Service Rate	$/kW	0.1698
	$/kW	
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017	$/kW	0.4427
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017 Applicable only for Non-Wholesale Market Participants	$/kW	(1.0052)
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017 Applicable only for Non-RPP Customers	$/kW	2.4517
Rate Rider for Application of Tax Change – effective until the effective date of the next cost of service	$/kW	(0.0652)
Retail Transmission Rate - Network Service Rate	$/kW	1.4801
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1710

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Hydro One Orillia

TARIFF OF RATES AND CHARGES

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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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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 Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.56
Distribution Volumetric Rate	$/kW	15.1656
Low Voltage Service Rate	$/kW	0.1663
	$/kW	
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017	$/kW	0.4688
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017 Applicable only for Non-Wholesale Market Participants	$/kW	(0.9992)
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017 Applicable only for Non-RPP Customers	$/kW	2.4504
Rate Rider for Application of Tax Change – effective until the effective date of the next cost of service	$/kW	(0.0761)
Retail Transmission Rate - Network Service Rate	$/kW	1.4726
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1469

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator'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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Hydro One Orillia

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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

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Customer Administration		
Arrears certificate	$	15.00
Easement charge for unregistered rights	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection/Load Limiter	$	30.00
Collection/Disconnect/Load Limiter/Reconnect trip (at meter) - during regular hours	$	65.00
Collection/Disconnect/Load Limiter/Reconnect trip (at meter) - after regular hours	$	185.00
Collection/Disconnect/Load Limiter/Reconnect trip (at pole) - during regular hours	$	185.00
Collection/Disconnect/Load Limiter/Reconnect trip (at pole) - after regular hours	$	415.00
Other		
Temporary service install & remove	$	500.00
Specific Charge for Cable and Telecom Companies Access to the Power Poles - $/pole/year	$	41.28
Charge for LDCs Access to the Power Poles - $/pole/year	$	see below
Specific Charge for Generator Access to the Power Poles - $/pole/year	$	see below
Service Layout Fee – Basic	$	635.00
Service Layout Fee – Complex	$	845.00
Crossing Application – Pipeline	$	2,540.00
Crossing Application – Water	$	3,225.00
Crossing Application – Railroad	$	6,095.00
Line Staking - $/meter	$	4.95
Central Metering – New Service < 45 kW	$	120.00
Conversion to Central Metering < 45 kW	$	1,045.00
Conversion to Central Metering > 45 kW	$	925.00
Tingle Voltage Test in excess of 4 hours – per hour (average 2 additional hours)	$	140.00
Standby Administration Charge – per month	$	520.00
Connection Impact Assessment (CIA) Charge – CAE Small DG & Net Metering	$	5,620.00
Connection Impact Assessment (CIA) Charge – Greater than CAE Small DG & Net Metering	$	12,055.00
Sentinel Lights Rental Rate – per month	$	9.25
Sentinel Lights Pole Rental Rate – per month	$	4.15
Joint Use for Municipality Streetlights per year	$	2.04

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Specific Charge for LDCs Access to the Power Poles ($/pole/year)

LDC Rate for 10’ of power space	$	47.34
LDC Rate for 15’ of power space	$	56.81
LDC Rate for 20’ of power space	$	63.44
LDC Rate for 25' of power space	$	67.23
LDC Rate for 30' of power space	$	71.02
LDC Rate for 35' of power space	$	73.86
LDC Rate for 40' of power space	$	75.75
LDC Rate for 45' of power space	$	77.64
LDC Rate for 50' of power space	$	78.59
LDC Rate for 55' of power space	$	80.49
LDC Rate for 60’ of power space	$	81.43

Specific Charge for Generator Access to the Power Poles ($/pole/year)

Generator Rate for 10’ of power space	$	47.34
Generator Rate for 15’ of power space	$	56.81
Generator Rate for 20’ of power space	$	63.44
Generator Rate for 25' of power space	$	67.23
Generator Rate for 30' of power space	$	71.02
Generator Rate for 35' of power space	$	73.86
Generator Rate for 40' of power space	$	75.75
Generator Rate for 45' of power space	$	77.64
Generator Rate for 50' of power space	$	78.59
Generator Rate for 55' of power space	$	80.49
Generator Rate for 60’ of power space	$	81.43

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Effective and Implementation Date XXX X, 2016
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RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	No Charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0561
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0455

Ontario Energy Board (Board Staff) INTERROGATORY #5

Interrogatory:

Ref: Exh A/T1/Sch1
http://www.fin.gov.on.ca/en/guides/drc/101.html

Currently, except for Residential Class customers who are exempt from paying the Debt Retirement Charge(DRC), Orillia Power's customers pay a reduced DRC of $0.0049/kWh. Hydro One Network's customer classes excluding Residential Class customers pay the standard DRC, currently $0.007/kWh.

a) Please explain what DRC Hydro One is proposing to charge the former customers of Orillia Power, if the OEB approves this application. As necessary, please explain your response.

Response:

a) OPDC non-residential customers will continue to be charged the same reduced DRC of $0.0049/kWh during the deferral period or until further government direction regarding the DRC is provided.

Ontario Energy Board (Board Staff) INTERROGATORY #6

Interrogatory:

Ref: Attachment 9 - Tariff of Rates and Charges, p.13

Attachment 9
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Hydro One Orillia
TARIFF OF RATES AND CHARGES
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RETAIL SERVICE CHARGES (if applicable)

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		
More than twice a year, per request (plus incremental delivery costs)		

A portion of Orillia Power's Tariff of Rates and Charges effective May 1, 2016 is reproduced below.

EB-2015-0024

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

OEB staff notes that charges for "Electronic Business Transaction (EBT) system, applied to the requesting party 1) Up to twice a year and 2) More than twice a year, per request (plus incremental delivery costs)" are missing from the proposed Tariff of Rates and Charges.

a) If the omission of the charges for Electronic Business Transaction (EBT) system is an error, please correct.

b) If the applicants are proposing to eliminate these charges:
   i. Please provide reasons for this proposed change, including why this change is being requested as part of this consolidation application.
   ii. Please comment on whether this proposed change is considered an integral aspect of the consolidation, as referenced on page 11 of the *OEB's Handbook to Electricity Distributor and Transmitter Consolidations.*

Response:

a) Yes, this was a typographical error. Please refer to Exhibit I, Tab 1, Schedule 4, Attachment 1.

b) See a) above.

Ontario Energy Board (Board Staff) INTERROGATORY #7

Interrogatory:

Ref: Exh A/T2/Sch1/p.8

The application states that the City of Orillia(City) will retain the current Orillia Power operating centre on West Street for future redevelopment. Hydro One has agreed to enter into a five-year lease agreement with the City to lease this centre. Conditional on the completion of the sale, Hydro One intends to commence construction, during the lease period, of a permanent operations and administration building within the City of Orillia. This new centre will consolidate operations between Hydro One's pre-existing operating centre and the Orillia Power operating centre on West Street.

a) Please confirm whether Hydro One will build the operating centre if the proposed sale is not completed.

b) Please explain why Hydro One believes it is necessary to construct a new operations centre instead of expanding its existing centre or the Orillia Power operating centre and provide the anticipated cost of construction. Please confirm whether ratepayers will be expected to pay for this new centre.

c) Please advise where the new operating centre is expected to be situated relative to the existing operating centres of Hydro One and Orillia Power

d) Please confirm whether this centre is expected to serve customers other than the Orillia Power customers and explain why the operating centre is considered the best option for all customers.

e) Please comment on the anticipated effect of this change on service quality, reliability, and cost effectiveness/cost efficiency of electricity distribution for this acquired area.

Response:

a) The need for a new operations centre would still exist if this transaction was not contemplated. This solution will consolidate operations from three separate facilities used by Hydro One plus the OPDC facility into one operations centre, which will significantly lower annual operating costs. In the event the proposed sale is not completed, then the City of Orillia would not necessarily be the chosen location for the new centre.

b) The City is retaining the OPDC Operations Centre property and building for its own purposes, therefore it is not available for Hydro One's use beyond the lease term. Even if it was available, the current OPDC facility is undersized with no expansion potential and is located in the congested downtown area which is not ideally located to serve the expanded service territory.

The current Hydro One Operations Centre is too small and inflexible to meet both the current and future operating needs of the company. The construction of a new Operations Centre will consolidate these various dispersed Hydro One facilities, including the leased OPDC operations centre, leading to increased efficiencies. To situate within Orillia on a full serviced site that has excellent access to local, regional and highway routes, providing excellent coverage to the amended service territory will benefit all ratepayers. Hydro One expects to include the costs as well as productivity savings of any operations centre consolidation, whether benefited by Orillia or not, in its future rate filings, as the efficiencies and service improvements of this project will benefit all customers.

c) The new target site of the operations centre at Horne Business Park, University Avenue, Orillia, is approximately 5 km distance from OPDC's current operating and administrative Centre at 360 West Street South, Orillia.

The new site is approximately 7.5 km from Hydro One's current Oro Service Centre at 16 Small Crescent, RR#1 Hawkstone.

d) See the responses to parts a) and b).

e) The new Operations Centre will not impact service quality or reliability. Response times are dependent upon the magnitude of the event (e.g., storms vs. an isolated outage) and the number of staff required to respond to the outage. Geographic location of operation centres within a region is not the primary driver for outage response times but rather accessibility to the outage from the Hydro One crews' physical location (e.g., field work site or home location for after-hour calls). Responses to utility outages are not like other types of emergency responses, e.g., firefighting or ambulance service, in which responders depart from a central location. Other than leaving the initial work location in the morning, outage response would be similar to a police-type response where a dispatch may be taken at any location in which the utility outage responder is located at that point in time.

As previously discussed, this solution will consolidate operations from four facilities into one centre, which will be more operationally and cost efficient.

Ontario Energy Board (Board Staff) INTERROGATORY #8

Interrogatory:

Ref: Exh A/T2/ Sch1/p.9

The application states that Orillia Power's direct staff will be integrated into Hydro One's local operations and will become part of the area's pool of resources working within the larger Hydro One service area, which encompasses Orillia Power's current service territory. The application also states that although certain functions and positions will be eliminated as part of the integration process leading to efficiency gains, Hydro One, due to its size and current staff retirement profile, is able to offer continued employment to existing Orillia Power staff.

a) Please confirm whether all of Orillia Power's 15 direct staff will be absorbed by Hydro One.

b) Please provide an indication of the number of Orillia Power's indirect staff that are expected to move to positions within Hydro One.

c) Please comment on the functions/positions that Hydro One asserts will be eliminated, identifying whether these are indirect or direct staff positions and providing the number of positions that are expected to be eliminated as a result of this transaction.

Response:

a) Confirmed. All 15 direct staff are expected to move to positions within Hydro One.

b) All 23 indirect staff are expected to move to positions within Hydro One.

c) Hydro One will eliminate all 23 indirect staff positions solely focused on the OPDC territory in the management, back office, and indirect trades and technical areas.

   Hydro One will expand its current Zone 5 to include the OPDC service territory. The 15 direct positions, focussed solely on servicing the OPDC service area, will be eliminated. However, as a result of this transaction, 9 new local positions will be required and are anticipated to be sourced from the exiting 15 OPDC staff complement. Therefore, the result is a net reduction of 6 local trades and technical positions to serve the same territory.

Ontario Energy Board (Board Staff) INTERROGATORY #9

Interrogatory:

Ref: Exh A/T2/Sch1/p.11

The application states that sustained administrative efficiencies will result due to the elimination of redundant activities and efficiencies resulting from economies of scale and identifies certain Orillia Power activities as examples of what will be consolidated into Hydro One's portfolio of activities.

a) Please provide the cost savings that arise from these identified sustained efficiencies.

Response:

a) Ongoing administrative savings of approximately $2 million are forecast. See Exhibit I, Tab 1, Schedule 2, part b) for additional discussion of forecast savings.

Ontario Energy Board (Board Staff) INTERROGATORY #10

Interrogatory:

Ref: Exh A/T2/ Sch1/p.17

The applicants are requesting approval to continue to track costs to the regulatory asset accounts currently approved by the OEB for Orillia Power and to seek disposition of their balances at a future date. Regarding the applicants' plans for deferral and variance accounts:

a) *The Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* provides that under the Price Cap IR, the distributor's Group 1 audited account balances will be reviewed and disposed if the pre-set disposition threshold is met. In the letter *Update to EDDVAR Report, released July 2009*, dated July 25, 2014, distributors may seek to dispose Group 1 balances that do not exceed the threshold. Please confirm that the applicants' plan to request their deferral and variance accounts for disposition is consistent with this policy.

b) Please confirm that Orillia Power's deferral and variance accounts will be tracked separately from Hydro One Network's deferral and variance accounts.

Response:

a) Yes, Hydro One confirms that it will comply with this policy and will propose disposition of Group 1 balances once they meet the threshold established by the Board.

b) Confirmed.

Ontario Energy Board (Board Staff) INTERROGATORY #11

Interrogatory:

Ref: Exh A/T1/Sch1/p.3

The application states that the purchase price is subject to adjustment, within 90 days following closing.

a) Based on the most current information available, please provide an estimate of the final purchase price after these adjustments.

Response:

a) The adjustments to the purchase price per section 2.4 of the Share Purchase Agreement are related to working capital, changes to net fixed assets, changes to long-term debt and changes to regulatory asset balances. All these adjustments are subject to variability in the normal course of business, with some difficult to forecast and subject to large fluctuations month to month. For example, the global adjustment balance relates to costs that are outside of the control of either party to this transaction. Consequently, the provision of an estimate of these costs is not indicative of the final purchase price and has not been provided nor is an estimate available.

   Additionally, in accordance with the Handbook, the purchase price is only reviewed from the perspective of financial viability of the acquiring utility. Hydro One does not foresee any scenario where these adjustments will impact the ongoing financial viability of Hydro One Networks Inc.

Ontario Energy Board (Board Staff) INTERROGATORY #12

Interrogatory:

Ref: Exh A/T2/Sch1/pp.2,4,15
Exh A/T3/Sch1/p.7

The application states that the cost of providing a negative rate rider as well as incremental transaction and integration costs will be recovered from synergies generated from the consolidation.

a) Please explain whether these costs have been included in Table 1 of Tab 2. If yes, what is the quantum included per year.

b) Please confirm whether or not these costs have been included in the Earnings Sharing Mechanism (ESM) calculation pertaining to years 6 to 10.

Response:

a) No, they have not been included in Table 1 of Tab 2.

b) No, the negative rate rider is only effective between years 1 and 5 as per Exhibit A, Tab 2, Schedule 1, Page 3. As a result, there are no costs to include in the ESM in years 6 to 10.

Ontario Energy Board (Board Staff) INTERROGATORY #13

Interrogatory:

Ref: Exh A/T2/Sch1/p.12

The application states that Orillia Power's current debt will be retired by Orillia Power on or prior to the closing of this acquisition. However, Hydro One is to assume Orillia Power's debt for $14.9 million as a part of the acquisition cost.

a) Please clarify whether Orillia Power is retiring the debt prior to the closing or the transaction or whether Hydro One is going to assume the debt as a part of the transaction.

b) Please explain the flow of transactions to settle the debt, including where the funds to retire the debt are from and how the funds will flow through the relevant parties to settle the debt.

c) If Orillia Power is to retire the debt, please explain how Orillia Power retain sufficient cash flows to retire the debt and maintain operations.

Response:

a) OPDC's intention is to establish a new interest only demand loan with a major chartered bank in order to repay the amounts due to both the City (promissory note) and Infrastructure Ontario (loan) prior to closing.

   The newly established bank demand loan will remain outstanding upon closing of the sale transaction.

b) OPDC will utilize newly borrowed funds from a chartered bank to retire the City promissory note obligation and the Infrastructure Onatrio loan. The new demand loan will replace the former debt on OPDC's balance sheet.

c) There is no intention to immediately retire the debt.

Ontario Energy Board (Board Staff) INTERROGATORY #14

Interrogatory:

Ref: Exh/T2/Sch1/p.16
Attachment 12, Orillia Power Audited Financial Statements

According to the application, Hydro One will pay $41.3 million for the acquisition of Orillia Power comprised of a cash payment of of approximately $26.4 million and the assumption of short term and long term debt of $14.9 million (including regulatory deferral account balances). The 2015 net book value of Orillia Power’s assets is $22.5 million.

a) Please provide a breakdown of the short term debt, long term debt and other components of the $14.9 million. For each debt item, please provide the date, amounts and interest rates, totaling $14.9 million.

b) If the $14.9 million is valued as at December 31, 2015, please reconcile the amount to Orillia Power’s 2015 audited financial statements.

c) Please show how the $22.5 million net book value is calculated from Orillia Power’s 2015 audited financial statements.

d) Please show the calculation of the “premium” Hydro One is paying above the book value of Orillia Power’s assets, factoring in Hydro One’s debt assumption.

Response:

a) Please refer to Attachment 1.

b) Please refer to Attachment 1.

c) The net book value of OPDC’s fixed assets of $22.5 million is sourced from the 2015 audited Financial Statements, as provided in Exhibit A, Tab,1, Schedule 1 Attachment 12, and is shown below:

Financial Statement Items	**$000s**
Property, plant and equipment	23,586
Intangible assets	125
Less: Deferred revenue (capital contribution)	(1,166)
Net Book Value of Fixed Assets	**22,545**

d) As per OPDC's 2015 audited Financial Statements provided in Attachment 12 to this Application, the estimated Goodwill as at 31 December, 2015 would be approximately $13.7M.

Values as at December 31, 2015	**$000s**
Total Assets acquired[1]	36,628
Total Liabilities acquired	(23,992)
Net Assets acquired	**12,636**
Purchase Price	26,350
Less: Net Assets acquired	(12,636)
Estimated Goodwill	**13,714**

[1] The calculation of Net Assets Acquired is expected to be adjusted to reflect the inclusion of a Deferred Tax Asset that will be recognized in association with OPDC exiting from the Payment-in-Lieu of Taxes (PILs) regime. As a result of this adjustment, the Estimated Goodwill arising from this transaction is expected to decline, as it will be allocated to the Deferred Tax Asset.

RECONCILIATION OF OPDC ENTERPRISE TO EQUITY VALUE (share purchase price)

Enterprise Value			**41,269,000**
Less adjustments to arrive at equity value:			
DEBT - BOOK VALUE (per 2015 Audited Financial Statements)		**Note Ref**	
City Prommisory Note	9,762,000	(1)	
Infrastructure Ontario - long term	735,000	(2)	
Infrastructure Ontario - current portion	210,000	(2)	
Included in current liabilities _ TD bank indebtedness	2,000,000	(3)	
	12,707,000		-12,707,000
REGULATORY DEFERRAL ACCOUNT BALANCES (per 2015 Audited Financial Statements)			
Regulatory deferral debits	2,126,000	(4)	
Regulatory deferral credits	-2,987,000	(4)	
Year-end adjustments to deferred taxes	-1,351,000	(5)	
	-2,212,000		-2,212,000
Cash Value paid for shares per share purchase agreement			**26,350,000**

Note (1) Interest only note @ 6.25%. Principal due in 2030.

Note (2) 10 year debenture. Interest rate @ 4.39%. Principal is $210,000 per year. Due in 2020

Note (3) Interest only note at prime rate less 0.25%.

Note (4) Regulatory balances settled through annual and cost of service rate applications. Rates as est. by OEB

Note (5) Tax Balances impacting Deferred Tax assets and liabilities as estimated by Hydro One

Ontario Energy Board (Board Staff) INTERROGATORY #15

Interrogatory:

Ref: ExhA/T2/Sch1/p.17
ExhA/T3/Sch1/p. 8

In Tab 2, Hydro One requests approval for a regulatory account to track costs associated with the ESM. However, in Tab 3, the footnote indicates that Hydro One will file a separate application to request the establishment of the account at a later date.

a) Please clarify whether Hydro One is requesting for the OEB to establish this account as part of its determination of this application or whether Hydro One intends to apply for the establishment of this account at a future date.

Response:

a) Hydro One's intent was to obtain approval to establish and use a regulatory account to track costs associated with the ESM as part of this Application. If approval is granted, Hydro One will submit a Draft Accounting Order for the Board's approval either as a condition of this Application's approval, or as a subsequent filing.

Ontario Energy Board (Board Staff) INTERROGATORY #16

Interrogatory:

Ref: Exh A/T2/Sch1/pp.17-18

Hydro One is requesting approval to use USGAAP for accounting purposes in relation to Orillia Power so as to be consistent with Hydro One's accounting.

a) Please confirm that Orillia Power will retain sufficient records regarding any transition adjustments from IFRS to USGAAP to allow for testing of the transition adjustments in a future Orillia Power rate application.

b) If there is a material accounting standard transition adjustment (debit or credit) that impacts revenue requirement, please indicate whether Hydro One plans on requesting for a deferral account in a future application.

Response:

a) Hydro One will maintain adequate records to support any adjustments made as a result of transitioning OPDC from IFRS to USGAAP.

b) No, Hydro One does not plan on requesting a deferral account.

Ontario Energy Board (Board Staff) INTERROGATORY #17

Interrogatory:

Ref: Exh A/T2/Sch1/p.15

The application states that Hydro One intends to have one set of financial records after the companies are fully integrated stating that providing separate financial statements for Orillia Power would decrease forecast synergies and add costs.

The Handbook for Utility Rate Applications, dated October 13, 2016 indicates that in the first cost of service or custom IR application following consolidation, the OEB will consider the savings that have been generated through the consolidation.

a) Please confirm that Hydro One is not planning to track any costs or savings associated with the acquisition. If so, please explain how Hydro One will present information on the savings.

b) Please explain how Hydro One will ensure that the transaction and integration costs are not included in Hydro One's revenue requirement as indicated in Tab 2.

c) Please estimate what the reduction in savings would be if Hydro One tracked Orillia Power financial records separately.

Response:

a) Hydro One assumes that the reference should be Exhibit A, Tab 3, Schedule 1, Page 3 which addresses reporting post-integration.

As stated in that exhibit, Hydro One does not intend to provide separate financial statements for acquired utilities. Hydro One did not make any comments in this Application on whether or not it will separately track costs (OM&A and capital) related to serving OPDC customers. Hydro One is cognizant that after it filed this Application, the OEB released the "Handbook for Utility Rate Applications", which addresses MAADs, writing:

> *"The OEB has issued a Handbook to Electricity Distributor and Transmitter Consolidations that makes clear that rate setting is generally not a consideration in reviewing a consolidation through a merger, acquisition, amalgamation or divesture. In*

the first cost of service or Custom IR application following the consolidation the OEB will scrutinize specific rate-setting aspects of the MAADs transaction, including a rate harmonization plan and/or customer rate classification post consolidation. This will include consideration of:… the savings that have been generated through the consolidation…." [1]

Hydro One also notes that, subsequent to the release of the Handbook for Utility Rate Applications, the OEB released the LDC Co. Decision, EB-2016-0025. This Decision addressed the merger of three major utilities and the purchase of another urban utility, resulting in an entity with 960,000 customers and a rate base of approximately $2.5 billion[2]. The OEB did not require any reporting requirement on savings.

"The OEB notes that the applicants have proposed that LDC Co track the operations of each of the four predecessor utilities and that reporting to the OEB take place separately until December 31, 2019, when the completion of the consolidation of the four predecessor utilities is expected to occur. The Handbook, however, sets out that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers. The OEB is of the view that this principle continues to be applicable in this case. The OEB does not require, nor encourage reporting on a "separate" utility basis[3]."

Hydro One plans to fully integrate OPDC into its distribution business within 18 months of approval of this Application - at that time, consolidation will be completed. Hydro One believes that the direction provided in the LDC Co. decision is a reasonable approach, is consistent with the intent of the consolidation policies of the Board and will result in higher synergy savings which is in the best interest of customers.

b) Please refer to Exhibit I, Tab 1, Schedule 3b).

c) Hydro One estimates that the cost of maintaining fully separate financial records for OPDC to be upwards of $500,000 annually. This estimate includes costs for additional finance personnel, maintenance of financial systems required for separate financial records and the cost of having the standalone financial statements audited. It does not include incremental costs for regulatory (e.g., rate applications, RRR) and tax compliance.

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[1] Handbook to Utility Rate Applications, Page 21
[2] EB-2016-0025, Decision and Order dated December 8, 2016, Page 3
[3] IBID, Page 26

No analysis has been completed by Hydro One in regards to the impact on field operations and related costs if changes are required in how work is scheduled and tracked, to meet audit requirements. These costs could further reduce the annual overall savings Hydro One has targeted, as presented in Table 1 from Exhibit A, Tab 2, Schedule 1.

If the OEB were to require separate financial statement reporting for the operations of OPDC, this would constitute a change to the assumptions that underpin Hydro One's ESM proposal and it is Hydro One's conclusion that while the quantum of the inefficiencies cannot be calculated at this time, the effect would be to reduce efficiencies. As such, Hydro One would seek to withdraw its proposed guaranteed ESM. Instead, Hydro One would implement an ESM where excess earnings would be shared with customers on a 50:50 basis for all earnings that are 300 basis points above the approved ROE as reported in those financial statements. As separate financial statements would be required, overhead cost allocations would be considerably higher than provided for in Table 1 of Exhibit A, Tab 2, Schedule 1. This results in both Hydro One and ratepayers assuming the risk of synergy savings achievement, instead of just Hydro One's shareholder.

Ontario Energy Board (Board Staff) INTERROGATORY #18

Interrogatory:

Ref: ExhA/T3/Sch 1/p.4
Exh A/T2/Sch1/p.2, Table 1

Page 4 of Tab 3 states that the OM&A forecast used in the proposed ESM reflects an aggressive estimate of savings. Forecast OM&A are about one third of Orillia Power's status quo OM&A forecast.

a) What methodology did Hydro One use to derive the OM&A and capital forecasts?

b) Please explain what is meant by the term "aggressive" estimate.

c) Please explain whether the OM&A forecast used in the proposed ESM is the most aggressive estimate of savings. If not, please estimate the most aggressive OM&A savings that Hydro One believes is achievable.

d) Please comment on how achievable the estimated savings in Table 1 are.

Response:

a) Please refer to Exhibit I, Tab 1, Schedule 2, part e).

b) What Hydro One meant by the term "aggressive" estimate is that, contextually speaking, a 70% reduction in OM&A is a significant reduction in any business and is not easy to achieve. It depicts a commitment towards achieving savings that will ultimately benefit ratepayers. In comparison to other mergers and acquisitions where forecast OM&A savings were considerably lower, Hydro One believes that a 70% reduction in OM&A costs is an aggressive estimate but achievable given Hydro One's integrated operating model. For instance: LDC Co. forecast 15% ongoing savings in year 10[1]; the Cambridge North Dumfries acquisition of Brant County Hydro forecast savings of approximately $1.2 - $1.5 million per year or 53-66%[2] of Brant County's existing OM&A; and Lakeland Power and Parry Sound

[1] EB-2016-0025, Exhibit B, Tab 5, Schedule 2
[2] EB-2014-0217, Exhibit A, Tab 1, Schedule 1, page 4; Brant County Power Inc. 2012 Audited FS

Hydro forecast savings of approximately $300 thousand[3] represented 22% Parry Sound's existing OM&A. Additionally, this level of savings is comparable to Hydro One's recent LDC acquisitions.

c) Yes, this forecast is Hydro One's best estimate of achievable savings.

d) Table 1 represents Hydro One's best estimate of the likely level of savings achievable. Like any forecast, actual results may vary.

[3] EB-2013-0427, Page 5; Parry Sound 2012 Audited FS

Ontario Energy Board (Board Staff) INTERROGATORY #19

Interrogatory:

Ref: ExhA/T3/Sch 1/p.5

Page 5 of Tab 3 states that as a result of the risks assumed by Hydro One in committing to a guaranteed ESM, a 20% risk factor has been applied to the OM&A forecast.

a) Please explain how 20% was selected.

b) Please explain whether the 20% risk factor negates part of the aggressive forecast in OM&A as referenced above.

Response:

a) Hydro One did not complete an intensive analysis to come up with the 20% figure. Hydro One did take into consideration its previously filed MAAD applications (Norfolk, Haldimand and Woodstock) where the evidence provided OM&A tables presenting low, medium and high scenarios with a 20% variance applied to each. Hydro One believes that a 20% risk factor applied to forecast OM&A is reasonable given the aggressive forecast presented, especially as compared to other MAAD application's forecast savings (see Exhibit I, Tab 1, Schedule 18). Applying the 20% risk factor to the projected OM&A would result in forecast savings of approximately 60%, which is still comparable or better than other mergers and acquisitions (see Exhibit I, Tab 1, Schedule 18)

b) The risk factor does negate a portion of the forecast OM&A but it has not been proposed *just* to mitigate the risk of the OM&A forecast. Hydro One is committing upfront to sharing projected earnings 300 basis points over the approved ROE in years 6 to 10, regardless of whether such savings materialize. This means that all risks, both within Hydro One's control and outside of Hydro One's control (e.g., weather impacts (storm damage, load), interest rates, inflation, customer growth, etc.) are absorbed by Hydro One.

   Notwithstanding the risk factor, Hydro One's risk-adjusted forecast OM&A savings would still be substantial and still considerably higher than that forecast by other parties to MAAD transactions.

Hydro One maintains that a 20% risk factor on OM&A costs associated with forecast earnings 6 to 10 years in the future is both fair and reasonable, especially in light of the proposed ESM guarantee.

Please see Exhibit I, Tab 5, Schedule 13 for further discussion pertaining to the risks absorbed by the risk factor.

Ontario Energy Board (Board Staff) INTERROGATORY #20

Interrogatory:

Ref: Exh A/T3/Sch1/pp.7-9

On page 9, it is indicated that Hydro One is guaranteeing $3.4 million refund to former Orillia Power customers, which equates to 45% of Orillia Power's current OEB-approved revenue requirement.

a) The $3.4 million refund is cumulative over 5 years. The average annual refund is $680k, which represents 9% of Orillia Power's annual revenue requirement. Please explain whether Hydro One still views this as a significant amount to be refunded.

b) In the same format as the ESM calculation in Table 6, please show and indicate the nature of the reductions in each of the revenue requirement components from Orillia Power's current OEB-approved revenue requirement to the forecasted revenue requirement in years 6 to 10 in Table 6.

Response:

a) Yes, Hydro One views this as a significant amount to be refunded. This refund is in addition to the fact that OPDC's customers have had their base distribution delivery rate reduced by 1 % and then frozen for five years. Furthermore, in years six through ten, rates will only increase by an inflationary adjustment. The culmination of these changes will result in a significant reduction in comparison to the status quo rebasing schedule of OPDC. This comparison is consistent with page 19 of the LDC Co. decision, where the Board determined that:

> *"As discussed earlier, the proposal should be compared to the status quo scenario, from an earnings potential perspective, whereby each utility could rebase at least once more within the 10 years, and any earnings above 300 basis points over the regulated rate of return would all flow to the shareholder until rates were reset. The OEB finds that customers will [be] not be harmed and will likely benefit in the long term from the enduring benefits of scale enhancements of service delivery arising from this transaction. In view of the policy objectives of this incentive scheme, the OEB does not consider the particular outcomes related to potential earnings relative to the status quo to be unreasonable".*

b) The individual components of OPDC's most recent Board approved revenue requirement have been added into Table 6 from Hydro One's Exhibit A, Tab 3, Schedule 1 and is provided below.

It is important to note OPDC's last Board approved revenue requirement is for the rate year 2010, and is 12 years prior to the first year of the proposed ESM, beginning in 2022.

The Column marked 'A' contains those revenue requirements components approved in OPDC's last rebasing from EB-2009-0273.

Table 6: Earning Sharing Mechanism Sharing - Years 6 to 10
Updated to include OPDC's 2010 OEB Approved Revenue Requirement Components ($000's)

Deferral Period Year	**A[1]**	**6**	**7**	**8**	**9**	**10**
Calendar Year	**2010**	**2022**	**2023**	**2024**	**2025**	**2026**
Rate Base	20,806	40,231	41,869	43,576	45,371	47,242
Equity Component of Rate Base	8,322	16,092	16,748	17,430	18,148	18,897
Revenue	7,656	8,600	8,792	8,996	9,199	9,410
OM&A[2]	4,346	2,090	2,137	2,186	2,237	2,288
Depreciation	1,408	1,036	1,091	1,147	1,211	1,278
Interest	739	1,429	1,488	1,548	1,612	1,679
Tax	343	849	865	881	893	905
Net Profit After Tax (Return on Equity)	**$820**	**$3,196**	**$3,211**	**$3,234**	**$3,246**	**$3,260**
Achieved ROE (%)	9.85%	19.86%	19.18%	18.55%	17.89%	17.25%
Less: Approved ROE% for OPDI	-	(9.85%)	(9.85%)	(9.85%)	(9.85%)	(9.85%)
ROE% above Approved ROE%	-	10.01%	9.33%	8.70%	8.04%	7.40%
Less: 300 Basis Points Threshold	-	(3.00%)	(3.00%)	(3.00%)	(3.00%)	(3.00%)
Total Over-Earnings (%)	-	7.01%	6.33%	5.70%	5.04%	4.40%
Total Over-Earnings	-	$1,128	$1,059	$994	$914	$832
50% of Overearnings Shared with to OPDC customers	-	$564	$530	$497	$457	$416
Tax Effected Earnings Sharing (26.5%)	-	$767	$721	$676	$622	$566
Cumulative Tax Effected Earnings Sharing (Years 6 to 10)	-					**$3,352**

[1] EB-2009-0273 Approved
[2] Includes risk factor adjustment

Ontario Energy Board (Board Staff) INTERROGATORY #21

Interrogatory:

Ref: ExhA/T3/Sch1/pp. 5-7, Tables 5-6
ExhA/T2/Sch1/p.12

In Table 5, the ESM is calculated based on the cost of debt embedded in Orillia Power's current approved rates. In Tab 2, it is indicated that Orillia Power's current cost of borrowing is higher than Hydro One's and Orillia Power's current debt will be retired prior to the closing of the acquisition. Savings will arise as a result of Hydro One's ability to refinance Orillia Power's debt at a lower rate.

a) Please explain why Orillia Power's current approved cost of debt is used in the ESM calculation and not a lower debt rate upon refinancing.

b) Please quantify the impact to the ESM calculation using the debt rate at which Hydro One believes it will be able to refinance the debt of Orillia Power.

Response:

a) The OPDC debt rate was used to determine the revenue requirement that was established and approved in OPDC's last cost of service application which underpins the current rates charged to OPDC customers. Consistent with the Board's RRFE Policies and the Handbook for Utility Rate Applications, utilities whose rate setting plan expires during the deferral period would apply an annual adjustment to their Board-approved rates; they do not reset their revenue requirement annually to reflect changes to debt rates and/or equity returns. OPDC is considered to have been on Price Cap IR, or its predecessor incentive ratemaking adjustment mechanism, since its last rebasing. The Handbook to Electricity Distributor and Transmitter Consolidations outlines rate setting options during the deferral period which are consistent with the above reports, whereas until the utility rebases its rates, an adjustment mechanism is used to apply changes on a distributor's rates on an annual basis.

The inability to modify debt rates is a risk that Hydro One is undertaking in proposing the guaranteed ESM sharing amount, meaning that if debt rates were to rise in the ten year period, Hydro One's forecast earnings would diminish, yet OPDC ratepayers would still receive the same ESM over-earnings refund. The proposed ESM is based upon the last approved debt rate for OPDC. If this rate is not accepted, then the ESM as proposed would be subject to annual true up for both ROE and debt rates. The calculation would be based upon the same rate base, OM&A and depreciation as outlined in Table 6 of Exhibit A, Tab 3, Schedule 1, but the calculation of interest expense, net profit and overearnings would be adjusted to take into account the change in both debt and equity rates.

b) Hydro One will not be undertaking any specific debt issues for the refinancing of OPDC debt. The refinancing of this debt will be included as part of the borrowing requirements of the overall Hydro One Distribution business.

Hydro One Distribution's current Board approved long-term debt rate included in the determination of its 2017 rates is 4.43% (as per EB-2016-0081).

If Hydro One's long-term debt rate of 4.43% was used in the proposed ESM model, the increase in the ratepayer's share of excess earning over 300 basis points would be $1,112 thousand, over the 5-year period. As per part a) above, this assumes there is no change to interest rates over the entire 10-year period.

Mr. Frank Kehoe INTERROGATORY #1

Interrogatory:

What method did Hydro One use to determine the purchase price (book value, current value, other) for the transaction subject to the application?

Response:

Hydro One notes that this interrogatory posed by Mr. Makuch, explores items that are outside the purview of this proceeding. Procedural Order 1 says:

> *"Parties should not engage in detailed exploration of items that do not appear to be relevant and material to the OEB's review of a consolidation application. Parties should refer to the OEB's Handbook to Electricity Distributor and Transmitter Consolidations, for what the OEB considers in its review, in developing interrogatories"*[1].

The aforementioned Handbook states that the application of the no harm test is limited to the effect of the proposed transaction on the OEB's statutory objectives, and that the OEB will not consider whether a purchasing or selling utility could have achieved a better transaction than that being put forward for approval in the application[2]. The OEB Handbook also states that "the selling price of a utility is relevant only if the price paid is so high as to create a financial burden on the acquiring company. This remains the relevant test"[3].

Hydro One has answered OWLPC's interrogatory in consideration of the above.

The $41.3 million purchase price represents the commercial value of the underlying assets established through negotiations with an arm's length third party.

The contemplated transaction has set a price for the all the shares of OPDC. Negotiations did not establish an individual price or value for each of OPDC assets.

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[1] PO1, Page 4
[2] Handbook to Electricity Distributor and Transmitter Consolidations, Page 9
[3] Handbook to Electricity Distributor and Transmitter Consolidations, Page 8

Mr. Frank Kehoe INTERROGATORY #2

Interrogatory:

Provide an itemized valuation of all specific components of the assets subject to the application, including: lands, building, easements, conductors, poles, transformers, substations, polymer insulators, inline switches, disconnects, mid span openers, CSC load interrupters, switches, isolator air brake switches, debt, good will, vehicles, specialized equipment, inventory and substations?

Response:

Please see Exhibit I, Tab 2, Schedule 1.

Mr. Frank Kehoe INTERROGATORY #3

Interrogatory:

What is the valuation given to all easements and all right-of-ways related to the Swift, Minden, Matthias and any other lines and subject to the application?

Response:

Please see Exhibit I, Tab 2, Schedule 1.

Mr. Frank Kehoe INTERROGATORY #4

Interrogatory:

Provide copies of all agreements between Ontario Hydro and the OWLPC that that may be affected by the transaction subject to this application, and specify the effect.

Response:

Hydro One has no central database of agreements to review in order to provide a complete response to this interrogatory. Two types of agreements between Orillia Power and Hydro One were considered by the parties in the context of the transaction, namely power supply agreements and power wheeling agreements. Neither type of agreement which would be affected by the transaction.

Mr. Frank Kehoe INTERROGATORY #5

Interrogatory:

Are any lands on the 6th concession, in the Township of Severn, subjacent and adjacent to the Trans- Canada Pipe Line, which are affected by the transaction subject to the application? If yes, what is the valuation allocated to them?

Response:

OPDC does own land on Concession 5 (not 6) in the Township of Severn which was formerly utilized as a terminal station. This land has minimal book value and is not required for the distribution company's current operations. Prior to the closing of the sale transaction it is to be sold for fair market value to Orillia Power Generation Corporation.

Please see Exhibit I, Tab 2, Schedule 1 with respect to the valuation.

Mr. Frank Kehoe INTERROGATORY #6

Interrogatory:

Explain, in plain language, the effect of the the transaction subject to the application, on the distribution debt payable to the City of Orillia. Is that debt and payable interest extinguished by this agreement?

Response:

Please see Exhibit I, Tab 1, Schedule 13.

Mr. Frank Kehoe INTERROGATORY #7

Interrogatory:

If not, does the City of Orillia still obtain any interest payment on this portion of this debt?

Response:

Please see Exhibit I, Tab 1, Schedule 13.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #1

Interrogatory:

Reference: Exhibit A/T1/S1, page 3 (lines 15-16) and page 6 (lines 17-18)
Exhibit A/T2/S1, page 8 (lines 1-4)
Attachment 5, page 38 of 84 (Section 6.3)

a) With respect to the planned Advisory Committee, please provide the terms of reference for the Advisory Committee.

b) If one has not been drafted, please provide the terms of reference for the comparable advisory committee established as a part of the Norfolk purchase (EB-2013-0187, Exhibit A/Tab 1/Schedule 1, page 3).

c) In order to illustrate the function/ role of the planned Advisory Committee, please indicate how frequently the Norfolk Advisory Committee has met since the purchase closed, what types of issues have been discussed and any specific initiatives HOI/HONI has undertaken as a result of the Committee’s input.

Response:

a) The terms of reference for the Orillia Advisory Committee have not been drafted at this time. Draft terms will be prepared in consultation with municipal staff and the Mayor for review at the first meeting of the Committee which will take place post-closing.

b) The terms of reference are created utility-specific, as outlined in part a) above. The Orillia Advisory Committee and its terms of reference will be crafted to reflect the unique communication needs of the Orillia community with input from the City and its community representatives. Therefore, comparing the terms or reference for the Norfolk Committee does not provide any indication of what will be included in the yet to be drafted terms for Orillia.

c) Please see part b) above. The frequency and subject of the meetings that occurred for Norfolk may not be indicative of what will occur for the Orillia Advisory Committee, once established.

The Hydro One Advisory Committee for Norfolk met three times post-closing of the Norfolk Power acquisition. At the third meeting it was agreed that the transaction and transition of the customers into Hydro One was successful and the committee was no longer required. The Mayor and other Norfolk County Committee members were comfortable that a solid working relationship had been established between the municipality and Hydro One which would not require the continuance of the Advisory Committee.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #2

Interrogatory:

Reference: Exhibit A/T1/S1, page 3 (line 17)
Attachment 5, page 38 of 84 (Section 6.2) & Schedule 6.2

a) What community events/programs has OPDC supported over the past two years and how does this compare with the list of community events/programs that Hydro One Networks proposes to sponsor/support?

Response:

a) OPDC supported various events/programs in 2015 and 2016 that targeted residential, GS<50 and GS>50 customers as well as students and the general public. These included:

- a table at the local Home Depot supporting Conservation Coupon programs in the spring and the fall
- tables at various local festivals including the Spring Home Show promoting Conservation programs, electrical safety and general customer education
- a business lunch in 2015 promoting Conservation programs for general service customers
- safety seminars for institutional/commercial customers and their contractors
- a trade show in 2016 promoting Conservation programs for general service customers and local suppliers
- visits to local schools by OPDC line crews in cooperation with the Kiwanis Children's Safety Village, promoting electrical safety and awareness
- OPDC line crew volunteers at OPP Family Day, with OPDC's Hazard Hamlet and bucket demos
- OPDC co-op employment program for local high school students to promote employment opportunities in the utility business
- OPDC staff participation at events promoted by the City of Orillia and various local organizations throughout the year
- OPDC staff participation in emergency planning meetings and events.

Hydro One's planned events are outlined in Schedule 6.2 of the Share Purchase Agreement provided as Attachment 5 of the Application.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #3

Interrogatory:

Reference: Exhibit A/T1/S1, page 6 (lines 14-16)
Exhibit A/T2/S1, page 14 (lines 12-22)
Attachment 5, page 39 of 84 (Section 6.8)

Preamble: While the January 2016 OEB Handbook (page 10) indicates that no evidence is required regarding public policy requirements such as CDM, the Application asserts that OPDC customers will benefit from provincial programs that are not currently included in OPDC's CDM Plan.

a) Please provide a schedule that compares the CDM programs (by sector) that OPDC has offered in 2015-2016 with those that HONI has offered over the same time period.

b) Please provide a schedule that compares the CDM programs OPDC currently proposes to offer in the future under its 2015-2020 CDM Plan with those proposed in HONI's 2015-2020 CDM Plan.

Response:

Please refer to Attachment 1.

CDM Program Offerings: Hydro One (HONI) and Orillia Power Distribution Corp. (OPDC)

Based on Hydro One's recently submitted CDM Plan to the IESO which is pending approval and OPDC's approved CDM Plan dated November 6, 2015.

Program Name	**Offered in 2015/2016**		**To be offered in future**		**Notes**
	HONI	**OPDC**	**HONI**	**OPDC**	
Residential					
Coupon Program	✓	✓	✓	✓	
New Construction Program	✓	✓	✓	✓	
Heating & Cooling Program	✓	✓	✓	✓	
Social Benchmarking Program	✓		✓		
Whole Home Program			✓	✓	This program is not a provincially-approved program as it is in the pilot phase.
Smart Thermostat Program			✓		
Commercial					
Retrofit Program	✓	✓	✓	✓	
Audit Funding Program	✓	✓	✓	✓	
High Performance New Construction	✓	✓	✓	✓	
Small Business Lighting	✓	✓	✓	✓	
Existing Building Commissioning			✓	✓	
High Efficiency Agricultural Pumping Program			✓		
Industrial					
Process & Systems Upgrade ("PSU")	✓	✓	✓	✓	
Energy Manager Program	✓		✓	✓	
Monitoring & Targeting			✓	✓	
Behind-the-Meter-Generation ("BMG")				✓	OPDC lists "BMG" as a proposed program that was to begin in 2016. Program has yet to be approved by IESO. BMG projects offered by HONI through PSU Program.
Low Income					
Home Assistance	✓	✓	✓	✓	

Program					
First Nations					
First Nations Conservation Program	✓		✓		
Pilots					
Air Source Heat Pump Pilot	✓				
Heat Pump Water Heater Pilot	✓				

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #4

Interrogatory:

Reference: Exhibit A/T2/S1, page 14 (lines 20-22)
Exhibit A/T2/S1, page 5 (lines 12-18)

a) What is the annual level of LEAP funding that OPDC has provided in 2015 and 2016?

b) Were OPDC's LEAP funds fully utilized in either 2015 or 2016 such that funds were not available to assist potentially eligible customers? If yes, please indicate for which years and when (during the year) funds were depleted.

c) Were HONI's LEAP funds (including top-ups provided by the Corporation) fully utilized in either 2015 or 2016 such that funds were not available to assist potentially eligible customers? If yes, please indicate for which years and when (during the year) funds were depleted.

d) The Application indicates that OPDC customers will be eligible for LEAP funding under HONI's LEAP. Will this impact the potential availability of LEAP funds to HONI's legacy customers? If yes, please indicate how. If not, please explain why not.

Response:

a) OPDC provided $9,200 annually for LEAP funding in each of 2015 and 2016.

b) The LEAP funds were fully utilized in 2015 and 2016 and were depleted both years by the end of March.

c) Hydro One's LEAP funds (including top-ups provided by the Corporation) assisted all potentially-eligible and approved customers in 2015 and 2016.

d) Hydro One is confident that Hydro One's annual contribution to the LEAP fund (including any top-ups provided by the Corporation) combined with the mandated annual distributor LEAP funding from OPDC, should result in no-harm to existing Hydro One legacy customer nor will OPDC's customer access to LEAP funding be affected.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #5

Interrogatory:

Reference: Exhibit A/T1/S1, page 5 (lines 18-20)
Exhibit A/T2/S1, page 17 (lines 1-2)
Attachment 12, page 22, Note 11

Preamble: The Application states that the OPDC regulatory assets currently approved by the OEB will continue to be tracked in their respective accounts and disposition will be sought at a later date.

a) Please provide a schedule listing OPDC's currently approved regulatory asset accounts; provide the balance in each as of December 31, 2015 and reconcile the total with the balance reported in Attachment 12 (page 22-Note 11). Please also provide the (unaudited balances) as of December 31, 2016 – if available.

b) Which of these regulatory asset accounts does HONI plan on continuing to make additions to (when warranted) after the transaction is completed?

c) In particular, does HONI propose to continue to track variances (post the transaction) for Accounts #1550, #1580, #1584, #1586, #1588 and #1589? If yes, please explain how HONI will ensure the requisite information for the current OPDC service area is available.

d) HONI indicates that disposition for these accounts will be sought at a later date. At the time of disposition, will HONI propose to refund/recover the balances just to/from customers in OPDC's current service area or also to/from HONI's legacy customers such that the latter will be impacted?

Response:

a) Note 11.3 to OPDC's audited 2015 Financial Statements (page 24 – Note 11), filed as Attachment 12 to this Application, provides the schedule listing regulatory asset account balances as of December 31, 2015. The schedule in excel format is provided as Attachment 1. Balances as of December 31, 2016 are not available at this time. All of these accounts have been approved for tracking by the OEB. In addition, OPDC has Board approval to use account 1592, HST/OVAT Input Tax Credits. However, at present, this account has a nil balance.

b) Hydro One plans to continue to make additional entries into all Group 1 Variance Accounts. Hydro One would also expect to make additional entries into the following accounts:
   a. LRAM, Account 1568,
   b. Stranded Meter Capital, Account 1555,
   c. Smart Meter Entity Variance, Account 1551
   d. Retail Costs, Account 1518/1548
   e. HST/OVAT Input Tax Credits, Account 1592

Hydro One would apply the prescribed carrying charges to Account 1508, Other Regulatory Assets, however new principal additions for this account are not foreseen. Additionally, no new entries will be entered in Account 1575, IFRS-CGAAP Transitional PP&E Amounts and Account 1576, Change in PP&E Useful Life Estimates as these relate to the transition to IFRS which will no longer be applicable to OPDC if approved by the OEB.

c) Confirmed. Hydro One will maintain the requisite information for these regulatory accounts for the current OPDC service area until the end of the deferred rebasing period.

d) Hydro One will propose disposition of the regulatory account balance through a rate rider applied to the customers in the service areas where the costs originated, i.e., back to customers in OPDC's current service area.

OPDC - Regulatory Account Balances

Note 11.3 Detail for regulatory account balances	Account #'s	31-Dec-15
Regulatory deferral account debit balances		
Low Voltage	1550	886,982
Stranded Meter Capital	1555	274,115
Payment in Lieu of taxes	1563	20,159
Lost Revenue Variance	1568	298,796
Network services - transmission	1584	66,155
Connection services - transmission	1586	53,851
Power	1588	145,760
Global adjustment	1589	1,131,184
Other Regulatory Assets	1508	9,224
Smart Meter Entity Variance	1551	11
Residual balance disposition / recoveries	1595	6,251
Regulatory deferral account debit balances - total		**2,892,488**
Regulatory deferral account debit balances (in thousands of dollars)		
Regulatory deferral account debit balances		**2,893**
Deferred income tax impact		767
Regulatory deferral account debit balances net of deferred taxes - Note 11.1		**2,126**
Regulatory deferral account credit balances		
Retail costs	1518 / 1548	63,292
IFRS-CGAAP Transitional PP&E Amounts	1575	13,563
Change in PP&E useful lives estimates	1576	1,936,348
Disposition / recoveries	1595	19,046
Wholesale market services	1580	2,030,932
Regulatory deferral account credit balances - total		**4,063,181**
Regulatory deferral account credit balances (in thousands of dollars)		
Regulatory deferral account credit balances		**4,064**
Deferred income tax impact		1,077
Regulatory deferral account credit balances net of deferred taxes - Note 11.1		**2,987**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #6

Interrogatory:

Reference: Exhibit A/T2/S1, page2 (line 11) – page 3 (line 2)
Attachments 2 & 4
OEB 2015 Yearbook

a) It is noted the OPDC customer count in Attachment 4 reconciles with the OEB's 2015 Yearbook. However, the HONI customer count in Attachment 2 does not. What is the source/basis for the reported HONI customer counts?

b) Please confirm that the 2015 HONI OM&A costs and customer counts used to derive the $173/customer cost for high density (UR) residential class are forecast values whereas the 2015 OM&A costs and customer counts for OPDC are actual values.

c) Please provide a schedule that compares the HONI's total forecast versus actual 2015 OM&A costs and that also compares the customer/connection counts as used in the Cost Allocation Model submitted with the 2015 DRO (EB-2013-0416) with the actual 2015 customer counts. (Note: Please include the individual forecast and actual customer/connection count for all HONI's customer classes).

Response:

a) The source for Hydro One's customer count is also the 2015 OEB Yearbook. The release of the 2015 OEB Yearbook, however, is dated prior to the completed integration of Haldimand County Hydro Inc. and Woodstock Hydro Service Inc. As a result, the current Hydro One customer figure, as provided in Attachment 2, is the total of the three individually reported LDCs, all as reported in the OEB Yearbook.

b) Confirmed.

c) Hydro One's forecast 2015 total OM&A costs were $543.1M and the actual 2015 total OM&A costs were $572.5M. The variance is predominantly attributed to one-time customer service costs in the 2015 year. Actual expenditures for Call Center Operations were higher than expected due to transition costs associated with a new outsourcing contract. Additionally, there was a major variance in Bad Debt expense, which was higher than the

OEB-approved forecast for 2015 due to the suspension of Hydro One’s collections program from May 2013 to early 2016 related to addressing the problematic implementation of the CIS.

A table showing the customer/connection counts used in the 2015 DRO and the actual 2015 customer counts is provided below:

Rate Class	**Number of Customers in 2015 DRO (mid-year)**	**Actual Number of Customers in 2015 (mid-year)**
UR	209,540	208,639
R1	433,844	432,519
R2	329,176	328,170
Seasonal	153,968	153,498
GSe	93,508	87,686
GSd	6,113	6,098
UGe	17,768	17,703
UGd	1,901	1,893
St Lgt	4,883	5,118
Sen Lgt	30,009	25,689
USL	5,642	5,264
DGen	1,010	893
ST	810	838
Total	**1,288,172**	**1,274,368**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #7

Interrogatory:

Reference: Exhibit A/T2/S1, page2 (line 11) – page 3 (line 2)
OEB 2015 Yearbook

a) Please confirm that the derivation of the $173/customer cost for HONI's UR class is based on the results of a Cost Allocation model that allocates OM&A costs to all of HONI's customer classes.

b) Please confirm that, in contrast, the derivation of the $362/customer for OPDC uses total OM&A costs but only includes the Residential, GS<50 and GS>50 customer counts (and not the counts for the Street Lighting, Sentinel Lighting and USL classes) in the denominator.

c) Based on HONI's 2015 DRO what are the OM&A costs per customer to serve the UG_e and UG_d customer classes

d) Based on the last Cost Allocation model submitted by OPDC to the Board, what percentage of total OM&A costs were allocated to the Residential, GS<50 and GS>50 customer classes?

Response:

a) Confirmed.

b) Confirmed. The OPDC OM&A cost per customer calculation is consistent with the calculation used to derive that ratio in the OEB 2015 Yearbook. As a result, the value is consistent with the value presented in the 2015 OEB Yearbook, specifically, $361.88/customer.

c) Based on Hydro One's 2015 DRO cost allocation model the UGe OM&A cost per customer is $444 and the UGd OM&A cost per customer is $4,620.

d) The percentage of total OM&A costs allocated to the Residential, GS<50 and GS>50 customer classes in the Cost Allocation model submitted by OPDC to the OEB are shown in the following table.

	Total	Residential	GS <50	GS>50
OM&A				
Distribution Costs	$1,783,000	$939,734	$292,094	$416,113
Customer Related Costs	$1,081,000	$780,005	$191,790	$106,961
General and Administration	$1,482,000	$884,176	$250,602	$274,577
	$4,346,000	$2,603,915	$734,486	$797,651
	100.0%	59.9%	16.9%	18.4%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #8

Interrogatory:

Reference: Exhibit A/T2/S1, page2 (line 11) – page 3 (line 2)

a) The Application indicates that the customer density for OPDC is roughly 58 customers per km. Please confirm that, based on this value, the customers would not qualify for treatment as HONI high density customers.

b) For those areas that HONI has currently designated as "high density", what is the average number of customers per km?

c) Please provide a schedule, based on the Cost Allocation provided with HONI's 2015 DRO, that sets out the per customer OM&A costs for the R1, GSe and GSd customer classes.

Response:

a) The 58 customers per km figure is based on Orillia's full service territory. Using Hydro One's methodology for defining density zones it is expected that a large core of the Orillia service territory would meet the 60 customers per km requirement to qualify for the high density rate classification. Also, at the time of integration ten years after closing of the acquisition, customer growth is expected to be such that the full Orillia service territory could meet the 60 customer per km requirement.

b) The average number of customer per km of line for the areas defined as urban high density is 65.2.

c) The per customer OM&A costs for the requested rate classes, based on the cost allocation model for the 2015 DRO, are provided below:

Rate Class	2015 OM&A Cost per Customer
R1	$263
GSe	$613
GSd	$6,726

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #9

Interrogatory:

Reference: Exhibit A/T2/S1, page2 (line 11) – page 3 (line 2)
OEB 2015 Yearbook

a) Please provide a schedule that contrasts the depreciation per customer for OPDC (based on the 2015 Yearbook) versus that for HONI's UR and R1 classes (based on the 2015 DRO).

b) Please provide a schedule that contrasts the NBV per customer for OPDC (based on the 2015 Yearbook) versus that for HONI's UR and R1 classes (based on the 2015 DRO).

Response:

a)

	OPDC	**HONI-UR**	**HONI – R1**
Depreciation per Customer	$83	$87	$150

b)

	OPDC	**HONI-UR**	**HONI – R1**
NBV of fixed assets per Customer	$1,676	$1,351	$2,515

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #10

Interrogatory:

Reference: Exhibit A/T2/S1, page 2 (lines 1-10) and page 9 (lines 10-16)

a) What were OPDC's actual total OM&A costs for 2015? If materially different (10%) from the forecast Year 1 Status Quo Forecast costs please explain why.

b) What portion of the OM&A reduction shown in Table 1 is due to the proposed elimination of 29 local positions (per page 9)? What are the sources for the balance of the assumed savings?

c) Please confirm that the Hydro One Forecast OM&A in Table 1 does not include any costs associated with administration or support services (e.g. back-office services, customer service, finance, human resources, distribution system planning& design, executive & governance, etc.).

d) It is noted that OPDC is just one of a number of recent acquisitions by HONI which also include Norfolk Power Distribution, Haldimand County Hydro and Woodstock Hydro. Cumulatively, have/will these acquisitions require HONI to add additional staff or retain additional contract services in order to provide administration and support services.

Response:

a) OPDC's actual OM&A spend for 2015 was $4.8 million. The Year 1 Status Quo Forecast is also $4.8 million.

b) The savings from reducing local positions by 29 is approximately $2.4 million per annum.

   The response to Exhibit I, Tab 1, Schedule 2 addresses the projected OM&A savings shown in Table 1.

c) Not confirmed. The Hydro One Forecast OM&A includes an evaluation of incremental administrative and support services costs as a result of absorbing the OPDC service territory.

d) The review of the costs associated with serving the acquired utilities referenced above will be subject to a future review and rate application by the OEB. When Hydro One files its 2018 to 2022 distribution rates application, per the Conditions of Approval of the above-mentioned MAAD acquisitions, Hydro One will provide a report on costs associated with these service areas.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #11

Interrogatory:

Reference: Exhibit A/T2/S1, pages 2 and 8

a) What is the anticipated annual cost of the five-year lease HONI is planning for the current OPDC Operating Centre (per page 8) and are these costs included in the Hydro One Forecast OM&A costs in Table 1? If not, how/where are they accounted for the determination of projected savings?

b) Will any of the lease costs be included in CIR Application HONI plans to file in 2017 (per page 5)?

Response:

a) The OPDC Operating Centre lease cost is estimated at $0.4 million annually. Table 1 includes lease costs for the first three years, after which time the new Hydro One Operations Centre is assumed to be in place.

b) No.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #12

Interrogatory:

Reference: Exhibit A/T2/S1, pages 8-11 and page 15

a) Please confirm that apart from the increase in the local complement of direct staff positions (per pages 9 & 15) HONI is not forecasting any increase in HONI's staff or contracted services will be required due to the acquisition of OPDC in order to provide administration or support services.

b) Page 9 states that OPDC's direct staff will be integrated into Hydro One's local operations servicing the larger Hydro One service area, which encompasses OPDC's current service area.
   i. Is this "larger Hydro One service area" serviced entirely out of Hydro One's Orillia Operating Centre referenced on page 8? If not what service centres are involved?
   ii. What is the number of direct staff currently employed by Hydro One at these service centres?
   iii. Please explain how Hydro determined that the direct staff required locally could be reduced by 6 positions following the transaction without affecting service quality/reliability.

Response:

a) Not confirmed. Please refer to the response to Exhibit I, Tab 3, Schedule 10, part c).

b) Presently Hydro One's current Orillia Operations Centre (located in Oro) has a direct staff complement of 15. These staff would integrate into the new Operations Centre once constructed.

   All existing Hydro One customers under the boundary of the existing Orillia Operations Centre and the existing OPDC customers will be serviced from the new consolidated centre.

   With regards to the reduction of 6 positions, presently OPDC Lines' staff perform work activity that is not considered "Powerline Maintainer" core work in a Hydro One Operating Centre. These activities include line vegetation management. Hydro One has a Utility

Arborist division that performs this work activity. Further, Provincial Lines has a designated work force responsible for large capital projects. There are significant efficiency gains by having a workforce that can be mobilized to construct a project start to finish uninterrupted. Under the current OPDC organization structure, these types of project crew activities would be interrupted whenever Customer Demand activity requires the resources.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #13

Interrogatory:

Reference: Exhibit A/T2/S1, page 2 (Table 1)

a) Please provide a schedule setting out OPDC's actual annual capital expenditures for 2013-2015. Please also include 2016 capital spending if available.

b) If the average annual spending for this period is materially different (10%) from the forecast Year 1 Status Quo Forecast costs please explain why.

Response:

a) Please refer to Attachment 1.

b) The status quo forecast provided in Table 1 for Year 1 is $2.7 million. The average capital spend for OPDC between 2013 -2015 was $2.8 million. The average spend estimated over the 2013-2016 period is $3.3 million which includes an atypical capital expenditure, specifically, the construction of a significant substation in 2016. The last similar capital expenditure of this nature was approximately 10 years ago. Consequently, Hydro One submits that, subject to excluding the outlier substation investment completed in 2016, the average annual spend over the 2013-2016 of $2.7 million is the same as that provided if the Year 1 Status Quo Forecast provided in Table 1 of Exhibit A, Tab 2, Schedule 1.

OPDC HISTORICAL CAPITAL EXPENDITURES FROM 2013 - 2015 WITH ESTIMATE FOR 2016

STATUS QUO FORECAST - YEAR 1 - CAPITAL EXPENDITURES (CAPEX)		2,700,000
2013 CAPEX - per Audited FS	2,724,000	0.9%
2014 CAPEX - per Audited FS	3,265,000	20.9%
2015 CAPEX - per Audited FS	2,311,000	-14.4%
Average CAPEX 2013 - 2015	**2,767,000**	**2.5%**
2016 CAPEX - per last year-end estimate available	4,995,000	85.0%
Average CAPEX 2013 - 2016	**3,324,000**	**23.1%**
2016 CAPEX - excluding capex for substation Note (1)	2,424,000	-10.2%
Average CAPEX 2013 - 2016 - excluding substation	**2,681,000**	**-0.7%**

NOTE (1) 2016 CAPEX includes the construction of a new substation - cost 2,571,000

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #14

Interrogatory:

Reference: Exhibit A/T2/S1, page 2 (Table 1) and pages 10-11

a) Would the construction of a new operations and administration building within the City of Orillia (per page 8, lines 6-11) be required if the transaction was not taking place? If yes, explain why?

b) What is the anticipated cost of the new operations and administration building and is this cost included in the Hydro One Forecast capital costs (per Table 1)? If not, why not?

c) Will any of the capital cost of the new operations and administration building be included in CIR Application HONI plans to file in 2017 (per page 5)?

d) Please explain in more detail the basis for the lower capital spending under the Hydro One Forecast versus the Status Quo and how it will be achieved without reducing reliability or the quality of service to former OPDC customers.

Response:

a) Refer to Exhibit I, Tab 1, Schedule 7.

b) As a new operations centre is needed, independent of the proposed transaction, and will benefit all customers, the facility was not included in the Hydro One forecast capital costs related to OPDC. See Exhibit I, Tab 1, Schedule 7 for further discussion of the operations centre need.

c) Yes, the next Hydro One Distribution rate filing will include capital costs for a new operations centre in Orillia. These expenditures will be defended in that application.

d) Refer to Exhibit I, Tab 1, Schedule 2, part e).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #15

Interrogatory:

Reference: Exhibit A/T2/S1, pages 3-5
OEB Handbook to Distributor and Transmitter Consolidations and
Filing Requirements for Consolidation Applications, January 2016 (the "Handbook")

a) Does HONI expect the transaction to be completed in 2017 or 2018?

b) Please confirm that, if completed in 2017, HONI will be in the last year of its current CIR Plan (per page 5) and OPDC would have been on Price Cap IR (PCIR). If not, please clarify the existing price setting approaches in 2017 for each distributor.

c) Table 1 (page 15) of the Handbook sets out the various rate setting alternatives available to the consolidated distributor during the deferral period in such a situation (second column). None of these alternatives appear to provide for the rebasing of the distributor currently on the CIR Plan during the deferral period. Assuming the transaction is completed in 2017 please explain how HONI's plan to rebase and file for a new CIR Plan for 2018-2022 for its legacy customers is consistent with the Board policy as set out in the Handbook.

d) Given that Hydro One is requesting a 10-year deferral period, how does HONI plan to set rates for its legacy customers for the balance of the deferral period after 2022? If it does not plan to set the rates post 2022 using the PCIR approach, please explain how the proposed approach is consistent with requirements set out in Table 1 of the Handbook.

Response:

a) Per the Share Purchase Agreement, if the OEB approves this Application, Hydro One expects to close the transaction within approximately 90 days of that approval.

b) Confirmed.

c) On page 14 of the Board's Handbook to Electricity and Transmitter Consolidations ("Handbook") the Board addresses situations that may not align with the "six potential scenarios" provided in Table 1:

> *"While Table 1 is intended to illustrate a situation of two consolidating distributors, the OEB is aware that future consolidations may involve several consolidating distributors as well as the possibility of multiple successive consolidation transactions by a single consolidated entity. For unique circumstances, the OEB may need to assess the rate-setting proposals on a case by case basis."*

Hydro One believes that the setting of rates of a large distributor that purchases a smaller utility is a unique situation which requires the Board to assess rate-setting on a case by case basis. Additionally, Hydro One has recently engaged in multiple successive consolidation transactions with the acquisition of three LDCs. It would not be reasonable to significantly disrupt the rate-setting regime of Hydro One Distribution for an acquisition of a company which represents approximately 1% of its customer base and 0.5% of its revenue requirement. Furthermore, the Handbook, on Page 17, identifies that exceptions from the policy may be required in situations such as this, where a large distributor acquires a small distributor.

In 2017, Hydro One plans to file a distribution rate application for 2018 to 2022 rates, which will include a rate setting proposal for the three recently acquired LDCs, as the three approved deferral periods will elapse during the proposed 2018-2022 timeframe. That application will not include any costs associated with serving the customers of OPDC.

Hydro One has proposed that OPDC's rebasing will be deferred for 10 years which will surpass the 2018-2022 timeframe that will be covered by Hydro One's next rebasing application. OPDC's rates will therefore be addressed in a future rate application beyond the 2018-2022 Hydro One Distribution rate application.

d) After 2022, Hydro One will apply to the Board to set future rates for its legacy customers and for any applicable acquired customers under the rate setting policies that are established by the Board and are in force at that time.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #16

Interrogatory:

Reference: Exhibit A/T2/S1, page 4 (lines 15-17)

a) Please provide a schedule setting out the specific services charges currently approved for OPDC and compare them with HONI's currently approved specific service charges.

b) What would have been the impact on OPDC's 2015 revenue from specific service charges if HONI's currently approved charges were used instead of OPDC's currently 2015/currently approved charges?

Response:

a) Attachment 1 provides a side-by-side comparison of the specific service charges as defined by the current approved rate orders of each LDC. Please note that although a specific charge may not be defined in the rate order, LDCs are allowed to recover either actual costs related to rendered miscellaneous service or a flat rate as documented in Section 11 of the OEB Rate Handbook Please refer to Exhibit I, Tab 1, Schedule 4 for further information.

b) If Hydro One's currently approved Specific Service Charges ("SSCs") were levied in lieu of the existing OPDC SSCs, OPDC's SSC revenue in 2015 would have increased by less than $100,000. This amounts to approximately 1% of OPDC's last approved revenue requirement. The increase would be predominantly attributed to the OPDC pole rental rates (equalling about half of current Hydro One rates) and the fact that OPDC does not charge customers for service layout requests.

Irrespective of the historical analysis, and the fact that SSC revenues are driven by customer requests and can vary significantly from year to year, Hydro One has outlined in response to Exhibit I, Tab 1, Schedule 4, that the OEB has initiated a comprehensive policy review of miscellaneous rates and charges applied by electricity distributors for specific activities or services they provide to their customers[1] since most of these SSCs do not reflect true costs of rendering the service. A subset of this review includes an assessment of wireline pole attachments and the methodology used for determining charges, including the appropriate

[1] EB-2015-0304

treatment of any revenues that carriers may receive from third parties. A Pole Attachments Working Group has been assembled to review these charges[2]. The existing charges levied by OPDC for access to the power poles by telecommunications carriers and cable companies is reflective of charges defined by the OEB 2006 Distribution Rate Handbook[3]. Hydro One's charge for the same item was updated and approved by the Board recently to be "…a just and reasonable pole attachment charge is $41.28 per pole, per year[4]". Consequently, Hydro One submits that it is reasonable to assume that OPDC SSCs related to pole rental rates would have been updated to align with current costs either through an OPDC request or through the policy review currently being undertaken by the Board.

With respect to service layout requests, Hydro One submits that it is more appropriate to collect costs associated with service layouts from the customer who requested the layout instead of all other ratepayers. This level of granularity in billing approach will be a benefit to the existing customers of OPDC.

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[2] EB-2015-0304 – OEB Letter – February 9, 2016
[3] 2006 OEB Distribution Rate Handbook, Page 110 – May 11, 2005
[4] EB-2015-0141 – OEB Decision and Order, Page 1 – August 4, 2016

Comparison of OPDC And HONI DX current Rate Schedules

		EB-2015-0024	EB-2016-0081
Customer Administration		**OPDC**	**HONI**
Arrears certificate	$	15.00	15.00
Statement of account	$	15.00	-
Easement letter	$	15.00	15.00
Income tax letter	$	15.00	-
Account history	$	15.00	-
Credit reference/credit check (plus credit agency costs)	$	15.00	-
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00	30.00
Returned cheque (plus bank charges)	$	15.00	15.00
Legal letter charge	$	15.00	-
Special meter reads	$	30.00	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00	30.00

Non-Payment of Account

Late payment (non Payment) - per month	%	1.50	1.50
Late payment - per annum	%	19.56	19.56
Collection of account charge - no disconnection	$	30.00	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00	
Disconnect/reconnect charges for non payment of account - at meter during regular hours	$	65.00	
Disconnect/reconnect charges for non payment of account - at meter after regular hours	$	185.00	185.00
Disconnect/reconnect charges for non payment of account - at pole during regular hours	$	185.00	185.00
Install/remove load control device - during regular hours	$	65.00	-
Install/remove load control device - after regular hours	$	185.00	-

Other

Temporary service - install & remove		-	500.00
Temporary service - install & remove - overhead - no transformer	$	500.00	-
Temporary service - install & remove - underground - no transformer	$	300.00	-
Temporary service - install & remove - overhead - with transformer	$	1,000.00	-
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	22.35	-
Specific Charge for Cable and Telecom Companies Access to the Power Poles - $/pole/year	$	-	41.28

Specific Charge for LDCs Access to the Power Poles - $/pole/year

LDC Rate for 10’ of power space	$		47.82
LDC Rate for 15’ of power space	$		57.38
LDC Rate for 20’ of power space	$		64.08
LDC Rate for 25' of power space	$		67.90
LDC Rate for 30' of power space	$		71.73
LDC Rate for 35' of power space	$		74.60
LDC Rate for 40' of power space	$		76.51
LDC Rate for 45' of power space	$		78.42
LDC Rate for 50' of power space	$		79.38
LDC Rate for 55' of power space	$		81.29
LDC Rate for 60’ of power space	$		82.25

Specific Charge for Generator Access to the Power Poles - $/pole/year

Generator Rate for 10’ of power space	$		47.82
Generator Rate for 15’ of power space	$		57.38
Generator Rate for 20’ of power space	$		64.08
Generator Rate for 25' of power space	$		67.90
Generator Rate for 30' of power space	$		71.73
Generator Rate for 35' of power space	$		74.60
Generator Rate for 40' of power space	$		76.51
Generator Rate for 45' of power space	$		78.42
Generator Rate for 50' of power space	$		79.38
Generator Rate for 55' of power space	$		81.29
Generator Rate for 60’ of power space	$		82.25

Service Layout Fee – Basic	$		640.00
Service Layout Fee – Complex	$		850.00
Crossing Application – Pipeline	$		2,555.00
Crossing Application –Water	$		3,250.00
Crossing Application – Railroad	$		6,120.00
Line Staking - $/meter	$		4.95
Central Metering – New Service < 45 kW	$		120.00
Conversion to Central Metering < 45 kW	$		1,050.00
Conversion to Central Metering > 45 kW	$		930.00
Tingle Voltage Test in excess of 4 hours – per hour (average 2 additional hours)	$		140.00
Standby Administration Charge – per month	$		520.00
Connection Impact Assessment (CIA) Charge – CAE Small DG & Net Metering	$		5,655.00
Connection Impact Assessment (CIA) Charge – Greater than CAE Small DG & Net Metering	$		12,130.00
Sentinel Lights Rental Rate – per month	$		9.51
Sentinel Lights Pole Rental Rate – per month	$		4.15
Joint Use for Municipality Streetlights	$		2.04

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #17

Interrogatory:

Reference: Exhibit A/T2/S1, pages 6-7
OEB Electricity Reporting and Record Keeping Requirements (RRR)

a) If available, please update Table 3 to include 2016 (either all or as much of the year as information for both utilities is available).

b) With respect to Table 3, please provide the contribution to the reliability metrics for HONI and OPDC for the following cause codes:
- Scheduled Outages
- Tree Contacts
- Defective Equipment

c) Please provide a table similar to Table 3 but that contrasts the performance of the two utilities with respect to the Service Quality metrics as reported in accordance with the Electricity RRR, Section 2.1.4.1.

Response:

a) Please note that OPDC's reliability numbers have been updated on the table below to exclude scheduled outages. This provides a closer comparison to Hydro One's reliability statistics. 2016 statistics are not yet available for OPDC.

	2013		**2014**		**2015**		**2016**	
	Hydro One	**OPDC**	**Hydro One**	**OPDC**	**Hydro One**	**OPDC**	**Hydro One**	**OPDC**
Duration (SAIDI)	2.82[1]	1.12	0.57	2.11	3.16	1.04	2.76	N/A
Frequency (SAIFI)	1.02	1.02	0.30	1.23	1.01	2.42	0.83	N/A

[1] This number has been updated from the original application to correct a typographical error – the statistic was originally entered as 2.28.

b) The following table stratifies the overall reliability metrics excluding loss of supply for OPDC and Hydro One provided in Table 3 by the cause codes - scheduled outages, tree contacts and defective equipment.

	2013		2014		2015	
	Hydro One	**OPDC**	**Hydro One**	**OPDC**	**Hydro One**	**OPDC**
Duration (SAIDI)	2.82	1.13	0.57	2.15	3.16	1.06
Frequency (SAIFI)	1.02	1.03	0.30	1.28	1.01	2.44
Scheduled Outages Contribution						
Duration (SAIDI)	0.00	0.01	0.00	0.04	0.00	0.02
Frequency (SAIFI)	0.00	0.01	0.00	0.05	0.00	0.02
Tree Contacts Contribution						
Duration (SAIDI)	2.78	0.06	0.02	0.13	0.93	0.01
Frequency (SAIFI)	1.01	0.02	0.01	0.01	0.39	0.00
Defective Equipment Contribution						
Duration (SAIDI)	0.02	0.56	0.04	0.10	0.00	0.92
Frequency (SAIFI)	0.01	0.31	0.01	0.21	0.00	2.11

c) The following statistics are as documented by the OEB through the annual OEB Yearbook for the years 2013 through to 2015. Please note that the data provided compares OPDC, a largely urban utility, against all of Hydro One, a predominantly rural utility. The regional granularity provided for the comparison of SAIDI and SAIFI in Table 3 is not readily available for these other metrics.

Unitized Statistics and Service Quality Requirements

	2013		2014		2015	
	Hydro One	**OPDC**	**Hydro One**	**OPDC**	**Hydro One**	**OPDC**
Low Voltage Connections (OEB Min. Standard: 90%)	97.40	100.00	97.40	100.00	97.50	100.00
High Voltage Connections (OEB Min. Standard: 90%)	100.00	N/A	100.00	N/A	N/A	N/A
Telephone Accessibility *(OEB Min. Standard: 65%)*	63.90	99.70	69.60	99.70	76.40	92.60
Appointments Met *(OEB Min. Standard: 90%)*	98.40	100.00	99.30	100.00	98.50	100.00
Written Response to Enquiries *(OEB Min. Standard: 80%)*	99.30	100.00	100.00	100.00	100.00	100.00
Emergency Urban Response *(OEB Min. Standard: 80%)*	N/A	100.00	N/A	100.00	N/A	100.00
Emergency Rural Response *(OEB Min. Standard: 80%)*	90.20	N/A	81.10	N/A	76.30	N/A
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	5.60	0.20	4.70	0.20	2.10	0.10
Appointments Scheduling *(OEB Min. Standard: 90%)*	98.70	100.00	99.30	97.00	98.50	97.20
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	87.10	N/A	95.10	N/A	96.20	N/A
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	97.30	100.00	95.70	100.00	98.10	100.00
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	99.70	100.00	100.00	100.00	99.78	100.00
Billing Accuracy *(OEB Min. Standard: 98%)*	N/A	N/A	94.63	99.98	98.59	99.98

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #18

Interrogatory:

Reference: Exhibit A/T3/S1

a) With respect to Tables 5 and 6, please indicate which elements of the ESM calculation will be based on forecast/set values (e.g., OM&A) that are known now and will not change and which elements are subject to future adjustment (e.g., Revenues based on future price cap adjustments). For those that will be subject to future adjustment, please indicate the basis for such adjustments.

b) Table 5 indicates that revenues will be based on “forecast load and customer profiles”. Please indicate what the basis for these forecasts will be (e.g. is it the forecast for 2010 used in OPDC’s last rebasing?).

c) Will the rate base used in the calculation include the value of OPDC’s current Operating Centre on West Street?

d) Please confirm that the value for working capital used in determination of the rates base will be that approved in EB-2009-0273. If not, how will it be established?

Response:

a) Hydro One’s proposed ESM has locked in the numbers presented in Table 6 based on the assumptions provided in Table 5. Therefore, Hydro One confirms that all the ESM model calculations are known now and will not be subject to future adjustment. Please see Exhibit I, Tab 1, Schedule 21 for further information.

b) Please refer to Exhibit I, Tab 4, Schedule 16. Hydro One confirms the revenue forecast is not the same revenue value approved in OPDC’s last rebasing.

c) Yes, the forecast rate base used in Hydro One’s ESM model is calculated from a starting point using NBV of PP&E and Intangible Assets information sourced from OPDC’s 2015 audited Financial Statements.

d) Confirmed.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #19

Interrogatory:

Reference: Exhibit A/T1/S1, pages 4-5
Attachment 1, page 2

a) The post-acquisition Corporate Structure suggests that OPDC will be a separate subsidiary of HOI. Please clarity whether this will be the case and, if yes, whether the additional costs (e.g. separate Board of Directors, etc.) have been accounted for in Table 1 (page 2).

b) If a separate subsidiary, please reconcile with the approvals requested which would cancel OPDC's distribution license and transfer its rate order to HONI.

Response:

a) Please see response to Exhibit I, Tab 1, Schedule 1a). The organization structure chart provided in Schedule 1 is immediately after the transaction and prior to full integration. Once OPDC is fully integrated into Hydro One, the OPDC box shown in Attachment 1, page 2 will no longer exist. As a result, there will be no separate Board of Directors, etc. required.

b) See part a) above.

Consumers Council of Canada (CCC) INTERROGATORY #1

Interrogatory:

Re: Ex. A/T1/S1

What is the primary objective of the acquisition for HON and HOI? What is the primary objective of the sale of the OPDC for Orillia Power Corporation and the Corporation of the City of Orillia?

Response:

Page 9 of the OEB Consolidation Handbook states:

> *"Also as set out in the Combined Proceeding decision, the OEB will not consider issues relating to the overall merits or rationale for applicants' consolidation plans [emphasis added] nor the negotiation strategies or positions of the parties to the transaction. The OEB will not consider issues relating to the extent of the due diligence, the degree of public consultation or public disclosure by the parties leading up to the filing of the transaction with the OEB."*

That said Hydro One believes the proposed consolidation will realize operational and organizational efficiencies which will have ongoing benefits for both ratepayers and shareholders. The City of Orillia believes the transaction will improve the overall economic outlook of its citizens, and Orillia Power Corporation wishes to work with its sole shareholder to help it achieve their objective while at the same time ensure that the best interests of Orillia's electricity ratepayers are taken into account over the long run.

Consumers Council of Canada (CCC) INTERROGATORY #2

Interrogatory:

Re: Ex. A/T1/S1

Please provide copies of all materials provided to HON's Board of Directors and Senior Management when seeking approval of this transaction.

Response:

Hydro One declines to provide the requested information as it is information not relevant to the relief sought in the Application. In support of this position, Hydro One relies on the Handbook. One of the objectives of the Handbook is stated at Page 1:

> *"The OEB has a statutory obligation to review and approve consolidation transactions where they are in the public interest. In discharging its mandate, the OEB is committed to reducing regulatory barriers to consolidation. In order to facilitate both a thorough and timely review of requests for approval of transactions, in this Handbook the OEB provides guidance on the process for review of an application, the information the OEB expects to receive in support, and the approach it will take in assessing the merits of the consolidation in meeting the public interest.*
>
> *Recent OEB policies and decisions on consolidation applications have already established a number of principles to create a more predictable regulatory environment for applications. This Handbook will provide further clarity to applicants, investors, shareholders and other stakeholders."*

Regulatory efficiencies in consolidation proceedings cannot be achieved if the evidentiary record is allowed to include information that pertains to matters outside of the OEB's stated considerations.

At page 3 of the Handbook, the OEB states that the Filing Requirements found in Schedule 2 set out the information needed for inclusion in an application. The scope of review to be carried out during a consolidation proceeding is discussed at page 9 of the Handbook. Confirmation is provided that deliberations, activities, and documents leading up to the final transaction agreement are not matters relevant for consideration when an application made pursuant to section 86(2) of the OEB Act.

The requested information concerns deliberations, activities and documents leading up to the final transaction agreement and this Application. As such, and based on the above reasons, Hydro One respectfully submits the information is not relevant to this proceeding and therefore declines to produce these materials.

Consumers Council of Canada (CCC) INTERROGATORY #3

Interrogatory:

Re: Ex. A/T1/S1

Please provide copies of all materials provided to the City of Orillia Board of Directors when seeking approval of this transaction. Please include any consultants' reports.

Response:

Please refer to Exhibit I, Tab 4, Schedule 2.

Consumers Council of Canada (CCC) INTERROGATORY #4

Interrogatory:

Ex. A/T1/S1/p. 5

HON is seeking approval at this time for a deferred rebasing period of 10 years for OPDC. HON also plans on filing a five-year Custom Incentive Regulation application for rates effective from 2018-2022 for its existing customer base. Please explain how this is consistent with the Board's Handbook. Please explain why HON's 2018-2022 Distribution application is not considered "rebasing".

Response:

Please see Exhibit I, Tab 3, Schedule 15.

Consumers Council of Canada (CCC) INTERROGATORY #5

Interrogatory:

Ex. A/T2/S1/p. 2

Please explain, in detail, how the “Projected Cost Savings” in Table 1 were derived. Please include all assumptions.

Response:

Please see Exhibit I, Tab 1, Schedule 2, part e).

Consumers Council of Canada (CCC) INTERROGATORY #6

Interrogatory:

Re: Ex. A/T2/S1/p. 3

Please explain the rationale for the 1% rate reduction for the first five years following the closing of the transaction. Is HON guaranteeing OPDC's customers that their rates will not exceed current rates with the 1% during the first 5 years of the 10-year deferred rebasing period? What is HON guaranteeing OPDC's customers with respect to bill impacts during the term of the plan? Under what circumstances would HON seek to rebase the rates of the OPDC rate zone prior to 2028?

Response:

The 1% rate reduction is a negotiated component of the commercial transaction between a willing buyer and a willing seller.

Hydro One has guaranteed that OPDC's 2016 approved base distribution delivery charge will be reduced by 1% for a period of five years.

For the 5-year period following expiry of the initial 5 year term, Hydro One has requested that the Board approve a Price Cap Adjustment Mechanism be applied to OPDC's 2016 approved base distribution rates and to use that mechanism to adjust those rates for each of years 6 through 10 of the deferral period. Additionally, Hydro One has also guaranteed a ratepayer refund through the implementation of an Earning Sharing Mechanism as explained in Exhibit A, Tab 3, Schedule 1, Page 8, Lines 6-15.

If the 10 year deferral period is approved as requested, Hydro One does not currently foresee any circumstance where it would seek to rebase the rates of the OPDC rate zone prior to the completion of the 10 year deferral period.

Consumers Council of Canada (CCC) INTERROGATORY #7

Interrogatory:

Ex. A/T2/S1/p. 3

Does Table 2: Bill Impacts for OPDC Customer set out the annual rate adjustment and bill impact for residential consumers for the first five years? What annual volume level has been assumed? Please set out the rate adjustment and bill impacts for customers at the 500, 750, 1000 and 1500 consumption levels.

Response:

The changes in base distribution delivery rates and total bill shown in Table 2 reflect what will be implemented in the first year after closing of the transaction to acquire OPDC (there will be no further "annual" rate adjustments). The reduced distribution rates will remain frozen for a period of five years, except as required to implement the Ontario Energy Board's direction to move to fully-fixed distribution rates for the residential class.

The rate adjustment and bill impacts shown in Table 2 assume a typical monthly consumption level for customers in those classes, which for the residential class is 750 kWh. The rate adjustment and bill impact at the requested levels of consumption, which is assumed to refer to a residential customer, are provided in the table below.

Monthly Residential Consumption (kWh)	Change in Base Distribution Delivery Rates	Change in Total Bill
500	(0.95%)	(0.25%)
750	(0.92%)	(0.20%)
100	(0.90%)	(0.17%)
1500	(0.88%)	(0.14%)

Consumers Council of Canada (CCC) INTERROGATORY #8

Interrogatory:

Ex. A/T2/S1/p. 3

Please provide one schedule setting out HON's current residential distribution rates (all rate classes) and OPDC's current residential rates.

Response:

Please refer to Attachment 1.

Hydro One Residential Rates

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0081

RESIDENTIAL SERVICE CLASSIFICATIONS

A year-round residential customer classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. All of the following criteria must be met:

1. Occupant represents and warrants to Hydro One Networks Inc. that for so long as he/she has year-round residential rate status for the identified dwelling, he/she will not designate another property that he/she owns as a year-round residence for purposes of Hydro One rate classification.
2. Occupier must live in this residence for at least four (4) days of the week for eight (8) months of the year and the Occupier must not reside anywhere else for more than three (3) days a week during eight (8) months of the year.
3. The address of this residence must appear on documents such as the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.
4. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Seasonal Residential customer classification is defined as any residential service that does not meet residential year-round criteria. It includes dwellings such as cottages, chalets and camps.

Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

Hydro One Networks' residential service area is sub-divided into three density zones according to the following:

- Urban Density Zone is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per circuit kilometer.
- Medium Density Zone is defined as areas containing 100 or more customers with a line density of at least 15 customers per circuit kilometer.
- Low Density Zone is defined as areas other than Urban or Medium Density Zone.

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, it should be noted that the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0081

RESIDENTIAL SERVICE CLASSIFICATIONS

YEAR-ROUND URBAN DENSITY – UR

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	24.78
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$	0.72
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers (see Note 13)	$/kWh	(0.0010)
Distribution Volumetric Rate	$/kWh	0.0094
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate (see Note 4)	$/kWh	0.0067
Retail Transmission Rate – Line and Transformation Connection Service Rate (see Note 5)	$/kWh	0.0047

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate – not including Capacity Based Recovery (see Note 12)	$/kWh	0.0032
Capacity Based Recovery (CBR) – applicable for Class B customers (see Note 12)	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP) (see Note 12)	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

YEAR-ROUND MEDIUM DENSITY – R1

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	33.77
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$	0.82
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers (see Note 13)	$/kWh	(0.0010)
Distribution Volumetric Rate	$/kWh	0.0230
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate (see Note 4)	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate (see Note 5)	$/kWh	0.0047

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate – not including Capacity Based Recovery (see Note 12)	$/kWh	0.0032
Capacity Based Recovery (CBR) – applicable for Class B customers (see Note 12)	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP) (see Note 12)	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0081

RESIDENTIAL SERVICE CLASSIFICATIONS

YEAR-ROUND LOW DENSITY – R2

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge*	$	80.33
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$	1.36
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers (see Note 13)	$/kWh	(0.0010)
Distribution Volumetric Rate	$/kWh	0.0374
Retail Transmission Rate – Network Service Rate (see Note 4)	$/kWh	0.0062
Retail Transmission Rate – Line and Transformation Connection Service Rate (see Note 5)	$/kWh	0.0044

* Under the Ontario Energy Ontario Energy Board Act, 1998 and associated Regulations, every qualifying year-round customer with a principal residence is eligible to receive Rural or Remote Rate Protection (RRRP). The service charge shown for eligible R2 customers will be reduced by the applicable RRRP credit, currently at $60.50.

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate - not including Capacity Based Recovery (see Note 12)	$/kWh	0.0032
Capacity Based Recovery (CBR) – applicable for Class B customers (see Note 12)	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP) (see Note 12)	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

SEASONAL

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	36.28
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$	0.84
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers (see Note 13)	$/kWh	(0.0010)
Distribution Volumetric Rate	$/kWh	0.0635
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate (see Note 4)	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate (see Note 5)	$/kWh	0.0042

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate – not including Capacity Based Recovery (see Note 12)	$/kWh	0.0032
Capacity Based Recovery (CBR) – applicable for Class B customers (see Note 12)	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP) (see Note 12)	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

OPDC Residential Rates

Orillia Power Distribution Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2015-0024

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	17.68
Rate Rider for Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	$	2.56
Rate Rider for Disposition of Account 1576 - effective until December 31, 2016 - Approved on an Interim Basis	$	(3.63)
Rate Rider for Application of Tax Change (2016) – effective until April 30, 2017	$	(0.08)
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0127
Low Voltage Service Rate	$/kWh	0.0006
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2017 Applicable only for Non-Wholesale Market Participants	$/kWh	(0.0028)
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Retail Transmission Rate - Network Service Rate	$/kWh	0.0054
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0041

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Consumers Council of Canada (CCC) INTERROGATORY #9

Interrogatory:

Ex. A/T2/S1/p. 4

Please set out a schedule which compares OPDC's Specific Service Charges and those approved for HON in the EB-2015-0079 rate order.

Response:

Please refer to Exhibit I, Tab 3, Schedule 16, Attachment 1.

Consumers Council of Canada (CCC) INTERROGATORY #10

Interrogatory:

Ex. A/T2/S1/p. 7

Please explain, specifically, how OPDC customers will benefit from operational efficiencies by having the OPDC assets integrated into HON's larger distribution system. When are these operational efficiencies expected?

Response:

The benefits of operational efficiencies post-integration that will be experienced by OPDC customers are documented in Exhibit A, Tab 2, Schedule 1, Pages 8 to 16. These operational benefits are expected to commence upon integration of OPDC into Hydro One which is expected to be completed within 18 months of the OEB's Decision and Order in this proceeding.

Consumers Council of Canada (CCC) INTERROGATORY #11

Interrogatory:

Ex. A/T2/S1/p. 15

Please provide a detailed breakdown of HON incremental transaction costs of $3 million. Please include all assumptions. What are OPDC's transaction costs? Please provide a detailed breakdown of these costs. How will these costs to be recovered? If these costs are to be funded though efficiencies and cost reductions specific to the OPDC business, how long will this take under the current forecasts?

Please explain how the estimate of between $5 million and $6 million of incremental up-front costs was derived. Please include all assumptions.

Response:

A breakdown of Hydro One's transaction costs is provided in the response to Exhibit I, Tab 1, Schedule 2, part d). These costs will be financed through productivity gains associated with the transaction. Based on the forecast of projected savings in Exhibit A, Tab 2, Schedule 1, Table 1, it will take four years post transaction close for the cumulative savings to reach the sum of the transaction and integration costs.

The City of Orillia is responsible for funding its own transaction costs and thus these costs will not be funded by ratepayers.

Integration costs are provided in response to Exhibit I, Tab 1, Schedule 2, part d). Integration is a complex exercise that involves the development and execution of integration plans for multiple lines of business. While the development of these plans is beyond the scope of this proceeding, there are three general components to integration: Customers, Assets and Employees. Integration of information concerning customers and assets is managed through Hydro One's finance, customer, work and outage management systems. These systems are highly integrated. Data will be transitioned from OPDC to Hydro One in several iterations of imports and validations as well as end-to-end testing cycles through Hydro One's systems/processes. Employee integration will occur following the integration of assets and customer information stages.

Consumers Council of Canada (CCC) INTERROGATORY #12

Interrogatory:

Ex. A/T2/S1/p. 17

The evidence states that the Incremental Capital Module ("ICM") will be made available for the Orillia business segment should the need arise.

a) Does HON expect to keep separate books for the Orillia rate zone? If so, for how long?
b) If separate books are not created, how would HON calculate the ICM materiality threshold?
c) Please explain how the ICM would work during the term of the plan?
d) Does HON expect it will apply for ICM relief during the plan term?
e) If ICM relief is granted during the plan term how can HON guarantee OPDC customers that rates in years 6-10 will not exceed inflation?

Response:

a) Please refer to Exhibit I, Tab 1, Schedule 17.

b) Hydro One will not need to keep separate books to calculate the materiality threshold, as provided in Appendix B of the Report of the Board, EB-2014-0219 *New Policy Options for the Funding of Capital Investments: Supplemental Report.*

   The calculation of the materiality threshold is based on OPDC's existing approved rate base and depreciation. Hydro One will be able to distinguish distribution revenues for OPDC to test against the materiality threshold.

c) If circumstances prevail where Hydro One does require an ICM, the details pertaining to the ICM will be provided in that application.

d) Hydro One currently does not plan to apply for ICM relief during the deferred rebasing period.

e) As explained in Exhibit I, Tab 4, Schedule 6, Hydro One has only guaranteed a mechanism for setting base distribution delivery rates. If ICM relief is ultimately sought and granted through a separate application, there would be no bearing on base distribution delivery rates in years 6 to 10.

Consumers Council of Canada (CCC) INTERROGATORY #13

Interrogatory:

Ex. A/T2/S1/p. 19

Please explain how HON will guarantee that the current customers of OPDC will be not be harmed under the proposed merger scenario. If rate levels upon rebasing are above what they would otherwise have been assuming the current OPDC cost structure how are these customers not harmed under the proposal?

Response:

The OEB, in the Decision and Order in Hydro One's acquisition of Woodstock Hydro Services Inc. (EB-2014-0213), wrote that it bases it decision on determining the No Harm Test on the cost drivers associated with the proposed transaction[1]. The proposed transaction will result in lower cost structures than otherwise would have been in the absence of the transaction, as has been detailed throughout this Application.

Rate setting beyond the deferral period are outside the scope of this transaction. Please see Exhibit I, Tab 3, Schedule 15.

[1] EB-2014-0213, Decision and Order, Page 9

Consumers Council of Canada (CCC) INTERROGATORY #14

Interrogatory:

Did HON or the City of Orillia undertake any consumer engagement regarding the proposed transaction? If not, why not? If so, please provide copies of all materials relating to that consumer engagement.

Response:

Hydro One declines to provide the requested information.

Page 9 of the OEB Consolidation Handbook states:

> *"Also as set out in the Combined Proceeding decision, the OEB will not consider issues relating to the overall merits or rationale for applicants' consolidation plans nor the negotiation strategies or positions of the parties to the transaction. The OEB will not consider issues relating to the extent of the due diligence, the degree of public consultation or public disclosure by the parties leading up to the filing of the transaction with the OEB [emphasis added]."*

The OEB reiterates this at pages 9-10 of the Handbook, in advising that applicants and stakeholders should not file certain types of information as they are not considered relevant to the proceeding. Among those types of information are "details of public consultation prior to the filing of the application".

Consumers Council of Canada (CCC) INTERROGATORY #15

Interrogatory:

Re: Ex. A/T3/S1

Would HON be supportive of earnings sharing mechanism ("ESM") prior to year 6? If not, why not? Would HON be supportive of an ESM that flowed 100% of the savings to customers? If not, why not? Why should OPDC customers have to wait 10 years to benefit from the proposed efficiencies?

Response:

No, Hydro One would not be supportive of an ESM proposal that commences prior to year 6. Hydro One's ESM proposal is consistent with the Board's Handbook, which states that:

> *"consolidating entities that propose to defer rebasing beyond five years, must implement an ESM for the period beyond five years[1]".*

Hydro One would not be supportive of an ESM that flowed 100% of the savings to customers. The OEB Policy states that there should be an appropriate balance of benefits and risks shared between ratepayers and shareholders of the consolidating entity in order to incent consolidation and efficiencies in the industry.

> *"While the OEB has determined that allowing a longer deferred rebasing period is appropriate to incent consolidation, there must be an appropriate balance between the incentives provided to utilities and the protection provided to customers[2]"*

This was also restated in the recent LDC Co decision:

> *"The OEB's incentive framework is intended to provide sufficient financial gains over and above the status quo to incent utilities to seek out merger or acquisition efficiency*

[1] OEB Consolidation Handbook, Page 16
[2] IBID, page 12

> *gains opportunities. The incentive framework is also intended to have customers share in large savings through earnings sharing beyond the 5-year deferred rebasing period*[3]*.*"

Hydro One has proposed to dispose of the accrued ESM at the end of the deferral period as this could provide or augment any rate mitigation that might be required at that time. This approach ensures that the regulatory principle of '*benefits follow costs*' is adhered to, by ensuring there is no cross-subsidization between Hydro One's legacy customers and the newly acquired OPDC customers – the OPDC customers through the funds accumulated in the deferral account will fund their own rate mitigation. At Exhibit A, Tab 3, Schedule 1, Page 8, three alternatives for disposition are provided. However, if the Board finds that disposition of the proposed ESM should occur at an earlier period in time, i.e., commencing in year six, Hydro One has no objections to doing so.

[3] EB-2016-0025, Decision and Order, Pages 18-19.

Consumers Council of Canada (CCC) INTERROGATORY #16

Interrogatory:

Re: Ex. A/T3/S1/p. 7/Table 6

Please provide a detailed explanation setting out how the forecast cost savings and benefits set out in Table 6 – Earning Sharing Mechanism – Years 6-10 were derived.

Response:

Please see Exhibit I, Tab 1, Schedule 2 for a description of the forecast cost savings. An explanation of Table 6 is provided below.

The ESM sharing calculation proposed flows from the OM&A and Capital cost savings and expenditure levels identified in Exhibit A, Tab 2, Schedule 1, Table 1 of this Application.

- Rate Base: The starting point for calculating OPDC's forecast rate base was OPDC's 2015 audited Financial Statements (Attachment 12 to Application). The forecast rate base equals the NBV of Property, plant and equipment ("PP&E") less Capital contributions plus a calculation for working capital, using the Board's methodology. During the 10 year rate rebasing deferral period, the rate base calculated includes additional in-service additions sourced from the forecast capital expenditures provided in Exhibit A, Tab 2, Schedule 1, Table 1, and applying the half-year rule. The modeling assumption used is that capital expenditures from Table 1 are treated as 100% in-serviced in the year incurred.
- Equity Component of rate base is 40% of the total rate base.
- Revenue: Forecast load and customer profiles were used to forecast revenue used in Hydro One's ESM model. These were generated by taking into account the latest information on Orillia's actual load and number of customers as well as local and provincial demographic and economic trends. The revenue forecast that Hydro One used in the ESM model includes adjustments for customer and load growth.
- Forecast OM&A used in the ESM model is sourced from Table 1 provided in Exhibit A, Tab 2, Schedule 1 with a 20% risk factor added. Please see Exhibit I, Tab 1, Schedule 19 for discussion regarding the OM&A risk factor used.
- Annual depreciation is calculated on the forecast NBV value of OPDC assets. These asset values are included as an input used to forecast the OPDC segment's rate base, as

outlined above. Hydro One's Board-approved depreciation rates are used which will also be used for financial accounting post transaction close.

- Interest expense is calculated by applying the long and short term debt rates outlined in Table 5 to 60% of the rate base.
- Tax expense is calculated using federal and provincial tax rates, at 26.5%.
- The elements described thus far were used to determine the forecast of net profit after tax.
- The achieved return on equity is equal to the net profit after tax divided by the equity component of rate base.
- The total over-earnings, stated as the percentage points in excess of the allowed ROE, is calculated by deducting the Board approved ROE of 9.85% from the achieved return on equity calculated in the previous step and deducting 300 basis points. This results in the total over-earnings percentage.
- Total over-earnings, stated in dollars, is the sum of the total over-earnings percentage multiplied by the equity component of rate base.
- That result is then split 50/50 between shareholder and customer and tax-affected by the current effective tax rate of 26.5%.

Consumers Council of Canada (CCC) INTERROGATORY #17

Interrogatory:

Re: Ex. A/T3/S1/p. 8

Please provide a forecast of the projected amount including interest that will accrue in the deferral account proposed for the "guaranteed refund" in year 10.

Response:

$3,465,000, inclusive of $113,000 of interest. Interest improvement is based on the current OEB prescribed interest rate (1.10%) for Q1 2017 as it relates to variance and deferral account balances.

Consumers Council of Canada (CCC) INTERROGATORY #18

Interrogatory:

Re: Ex. A/T2/S1/p. 3

The evidence states that 90% of OPDC's customers are residential. Please provide a current customer count for residential customers. Please indicate which of HON's rate classes these customers would qualify for.

Response:

As of December 31, 2016, OPDC serves 12,028 residential customers.

Hydro One has not to date performed any analysis or made any decisions regarding integration of OPDC customers into either, i) a currently established Hydro One Distribution rate class or, ii) a newly created rate class for those aforementioned customers. Per the Board's Decision in EB-2013-0196/EB-2013-0187/EB-2013-0198:

> *"Concerning the setting of future rates, it is the Board's expectation that at the time of rate rebasing HONI will propose rate classes for NPDI customers that reflect costs to serve the NPDI service area, as impacted by the productivity gains due to the consolidation."*

This guidance is further reiterated by the Board in the Consolidation Handbook as follows:

> *"Rate-setting following a consolidation will not be addressed in an application for approval of a consolidation transaction unless there is a rate proposal that is an integral aspect of the consolidation e.g. a temporary rate reduction. Rate-setting for the consolidated entity will be addressed in a separate rate application, in accordance with the rate setting policies established by the OEB. The OEB's review of a utility's revenue requirement, and the establishment of distribution rates paid by customers, occurs through an open, fair, transparent and robust process ensuring the protection of customers"*[1].

[1] Page 11

Consequently, future rate classification for OPDC customers will be addressed at Hydro One's first cost of service application which includes new rates for OPDC.

School Energy Coalition (SEC) INTERROGATORY #1

Interrogatory:

[Ex. A/2/1, p. 2] Please provide a table showing, based on current information the number of OPDC customers that would be in each of the Hydro One rate classes if they were assigned to those classes today.

Response:

Please see Exhibit I, Tab 4, Schedule 18.

School Energy Coalition (SEC) INTERROGATORY #2

Interrogatory:

[Ex. A/2/1, p. 2] Please provide the calculations behind Table 1, in live Excel format if they were prepared in that format.

Response:

See Exhibit I, Tab 1, Schedule 2, Attachment 2.

School Energy Coalition (SEC) INTERROGATORY #3

Interrogatory:

[Ex. A/2/1, p. 2] SEC is seeking to understand more clearly the tax and PILs impacts of the transactions in light of Hydro One's change in status from exempt under the Income Tax Act, Canada (the "Federal Tax Act"), to taxable in 2015.

a) Please confirm that, pursuant to section 149(1.1) of the Federal Tax Act, OPDC ceased to be exempt under that Act as of August 15, 2016, the date of the Share Purchase Agreement. If that is not the case, please provide the date OPDC ceased or will cease to be exempt, and the statutory references supporting your conclusion.

b) Please confirm that, pursuant to section 149(10) of the Federal Tax Act, as of the date it ceased to be exempt OPDC became liable to pay both federal and provincial income tax, with its first tax year starting at that time.

c) Please confirm that, pursuant to the same section, OPDC was on that same date deemed to have disposed of all of its assets, and reacquired them, at fair market value for both federal and provincial income tax purposes. Please provide full details of the calculation of that deemed disposition and reacquisition.

d) Please confirm that, as a result of the deemed disposition and acquisition, OPDC is required for accounting purposes to establish a deferred tax asset equal to the future tax benefit of the bump in tax values of its assets. Please provide the full calculation of the deferred tax asset (including any interaction with any existing deferred tax asset or liability), any forecasts the Applicants have as to when and how it will be drawn down (i.e. the impact on tax payable by OPDC and later by Hydro One annually until it is used up), and the Applicants' proposals for how that should be reflected in rates in the future.

e) Please provide a summary of the PILs consequences of the transactions, including the consequences of the deemed disposition and acquisition, any departure tax or transfer tax payable, and the amounts the timing of those payments, if any. Please provide full calculations of any incremental tax costs arising out of the transactions.

Response:

a) In signing the Share Purchase Agreement, Hydro One acquired a contingent right to acquire the shares of OPDC. Consequently, subsection 149(1.1) of the Income Tax Act (the "ITA") causes OPDC to become a corporation that is subject to corporate income tax under the ITA on its operating profits (i.e., OPDC will no longer qualify as a tax-exempt entity pursuant to paragraph 149(1)(d.6) of the ITA). The provisions of section 149(1.1) of the ITA would be applicable on the date of signing the Share Purchase Agreement ("SPA") by the parties.

b) OPDC will continue to be classified as a "municipal electrical utility" under section 88 of the Electricity Act, 1998 (Ontario) (the "EA") until it is ceased to be exempt from EA, which deemed to have occurred immediately prior to the date of the signing of the SPA as discussed in part a) above. OPDC will be liable to pay both federal and provincial income tax under the ITA with its first taxation year starting on the date of the signing of the SPA.

c) The above statement is correct. OPDC will be required to pay the "departure tax" as calculated pursuant to section 93 of the EA and section 12 of Regulation 162/01. This departure is deemed to arise immediately before the time that OPDC ceases to become exempt from making further payments in lieu of corporation tax under section 93 of the EA. There is no departure tax imposed on a capital gain that would be recognized prior to January 1, 2019.

Regarding part two of the question, OPDC believes providing full details of the calculation is premature. Section 2.8 - Valuation of Assets of the SPA requires that Hydro One and OPDC agree with the valuation of the assets. The information and facts will not be known and finalized until the closing of the purchase of OPDC. OPDC believes that this question is currently out of scope.

d) Confirmed. As a result of the deemed disposition and acquisition of the assets at fair market value from the departure of the PILs regime, OPDC will incur and pay a departure tax. For accounting purposes, OPDC is required to establish a deferred tax asset equal to the future tax benefit of the bump in tax values of its assets from the reacquisition at fair market value. The increase in the tax cost of the depreciable assets will result in a higher capital cost allowance that will be deducted in computing taxable income for tax purposes.

As stated in part c) above, OPDC has not completed a calculation of the deferred tax asset at this time.

The purchase price paid by Hydro One to acquire the assets for OPDC was a negotiated price, in which all parties to the transaction were aware that OPDC would be required to pay a departure tax from departing the PILS regime. Parties were also aware that the deferred tax asset was being purchased by Hydro One as part of the transaction. The premium on the purchase price of OPDC, as per the pre-filed evidence, is not a cost that is recoverable in rates. Consistent with the OEB's MAADs policy, recovery of the purchase price premium will be through the realization of synergies and other cost savings arising from the transaction. Based on the regulatory principle that benefits follow costs and given that the transaction does not relate to the provision of utility services, the benefit arising from the deferred tax asset should accrue solely to shareholders. The premium paid by Hydro One implicitly reflects the departure tax.

Hydro One has provided further information on in EB-2016-0160, Argument in Chief (see Attachment 1):

> *"In the context of whether tax allowances should or should not be included in a regulated utility's revenue requirement, the stand-alone principle has been framed as follows by this Board:*
>
> > *"In the Board's view, fairness in ratemaking requires adherence to the principle that a party who bears a cost should be entitled to any related tax savings or benefits."*[1]

The premium paid on the transaction and the departure tax liability resulting from OPDC departure from the PILs regime will not impact the books and records upon which rates are set; there is no impact on the ratepayer. The premium is financed by the shareholder and is outside of the rate regulated construct. As such, the benefit arising from the deferred tax benefit should also accrue to the shareholder.

e) The departure tax is addressed at part c) above. The Applicants do not believe that any transfer tax would be imposed by virtue of section 94 of EA and section 3(23) of Regulation 124/99.

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[1] Great Lakes Power Limited, EB-2007-0744, Decision and Order October 30, 2008, p.40; see also Great Lakes Power Transmission Inc., EB-2009-0408, Decision and Order, July 21 2010.

6. EXCLUSION OF IPO COSTS AND BENEFITS INCLUDING TAX BUMP

Exhibit C1-8-1 explains that as a result of HOL's shareholder selling more than 10 percent of the outstanding shares of HOL (through an initial public offering), Hydro One ceased to be subject

[210] Exhibit C1, Tab 4, Schedule 1, Page 14.
[211] See Exhibit I, Tab 1, Schedule 128 for discussion of the interrelation of share grants and base wage adjustments.
[212] Exhibit C1, Tab 4, Schedule 1, Table 4.

to the provincial Payments-In-Lieu of taxes regime (the "**PILS** regime") provided for in the *Electricity Act*[213] and its regulations ("**PILS Regulation**")[214] and became liable for federal income tax under the *Income Tax Act* (Canada) ("**ITA**")[215] and provincial income tax under the *Taxation Act, 2007* (Ontario) ("**OTA**").[216]

The departure from the PILS regime resulted in Hydro One actually paying $2.271 billion of payments in lieu of taxes under the PILS regime ("**Departure Tax**"). This occurred through five separate wire transfers made on November 4, 2015.[217]

Offsetting this Departure Tax was the creation of an allowable deferred tax asset. Under the PILS Regulation and subsection 149(10) of the federal ITA, the Departure Tax and the creation of the deferred tax asset were based on a deemed disposition and re-acquisition of Hydro One's assets at fair market value. The resulting increase in the cost of Hydro One's depreciable assets will allow it to claim higher capital cost allowance deductions in computing income for tax purposes.

One of the issues raised during the oral phase of the hearing appeared to be whether payment of the Departure Tax and creation of the deferred tax asset should be included or excluded from Hydro One's applied-for revenue requirement.

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[213] *Electricity Act, 1998,* SO 1998 c 15 (**"*Electricity Act*"**).
[214] O Reg 207/99 (**"PILS Regulation"**).
[215] RSC 1985, c 1 (5th Supp).
[216] SO 2007, c 11, Sch A.
[217] See Exhibit J11.16, Attachment 2, wherein description of the five wire transfers made to the Ontario Electricity Financing Corporation (**"OEFC"**) by Hydro One's Manager, Treasury Operations occurred on November 4, 2015.

(a) Governing Legal Principles: Stand-alone and Benefits Follow Costs

The determination of just and reasonable rates made pursuant to section 78 of the OEB Act are informed by three key regulatory principles: (i) cost causation, (ii) the stand-alone principle and that (iii) "benefits should follow costs".

The cost causation principle is well understood. Simply put, costs should be "borne by those who cause them to be incurred."[218]

The purpose of the stand-alone principle "is to notionally isolate and categorize – for accounting and rate-making purposes – the costs incurred in the operation of a discrete business function of a utility."[219] In so doing, ratepayers bear only the costs of the utility providing the regulated service.[220]

Application of the stand-alone principle is frequently relied upon in utility regulation.[221] Canadian regulators have consistently held that "only those costs and risks that pertain to the activities of the regulated utility in respect of the provision of service to ratepayers are reflected in the revenue requirement."[222] Conversely, the benefits that pertain to the activities of the non-regulated business are not subsidies given to the regulated utility.[223]

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[218] Lowell E Alt Jr, *A Practical Guide to the Retail Rate-Setting Process for Regulated Electric and Natural Gas Utilities* (Utah: Lowell E Alt Jr, 2006) at 72. See the Authorities at Tab 4.

[219] *ATCO Electric Limited v Alberta (Energy and Utilities Board)*, 2004 ABCA 215 at paras 171 & 176 (**"ATCO 2004"**). See the Authorities at Tab 5. For a comprehensive discussion of the stand-alone principle, see: Kathleen C McShane, "The Disposition of Tax Savings on Disallowed Expenses", submitted on behalf of the Coalition of Issue Three Distributors in EB-2004-0188 (12 January 2005) at Pages 6-15 (**"McShane Report"**). See the Authorities at Tab 6. The McShane Report was cited with approval in British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Decision, (10 May 2013).

[220] ATCO 2004 at paras 171-172. See the Authorities at Tab 5.

[221] ATCO 2004 at paras 171 & 176. See the Authorities at Tab 5.

[222] McShane Report at Page 2. See the Authorities at Tab 6.

[223] See, for example, AUC Decision 2011-399, EPCOR Distribution & Transmission Inc., Determination of Whether an Audit of Corporate Costs is Required (7 October 2011) at paras 42-44, citing with approval EUB Decision 2003-061, AltaLink Management Ltd. and TransAlta Utilities Corporation Transmission Tariff for May 1, 2002 – April 30, 2004, TransAlta Utilities Corporation Transmission Tariff for January 1, 2002 – April 30, 2002 (3 August 2003):

The stand-alone principle has been upheld by this Board in several instances, including the *2006 Electricity Distribution Rate Handbook*, the *Filing Guidelines for March 1, 2002 Distribution Rate Adjustments*, its *Natural Resource Gas Limited*[224] and *Consumers Gas*[225] decisions, among others.

In the context of whether tax allowances should or should not be included in a regulated utility's revenue requirement, the stand-alone principle has been framed as follows by this Board:

> "In the Board's view, fairness in ratemaking requires adherence to the principle that a party who bears a cost should be entitled to any related tax savings or benefits."[226]

In EB-2009-0408, the Board considered and applied the cost causation and stand-alone principles to circumstances where the tax liability in question arose outside of the regulated business and regulated costs of providing service to ratepayers.[227] The issue in that case concerned whether the calculation of income taxes by the regulated entity, Great Lakes Power Limited ("**GLPT**"), should be reduced or take into account the tax losses that had been incurred by an affiliated but non-regulated entity. The Board found as follows:

> Tax losses or deductions from outside the regulated business may result in no tax being paid by a particular entity (depending upon the corporate structure), but that does not mean the tax liability is not a real cost to the regulated business. The benefit of the tax losses arise from expenditures which remain outside the regulated business. *Ratepayers have not borne those expenses, and therefore are not entitled to the benefits arising*. The Board has addressed this issue in a number of different circumstances in the past. The most recent case involved Great Lakes Power Limited ("GLPL"), a predecessor company to GLPT, and the

"The underpinning of the stand-alone principle is that the regulated utility should not be subsidizing its non-utility operations or operations of members of its corporate family, neither should the non-regulated activities subsidize the utility operations." See the Authorities at Tab 7.

[224] EBRO 496 (20 August 1998).

[225] EBRO 376 I and II (30 January 1981).

[226] Great Lakes Power Limited, EB-2007-0744, Decision and Order (30 October 2008) at Page 40. See Authorities at Tab 8.

[227] Great Lakes Power Transmission Inc., EB-2009-0408, Decision with Reasons (21 July 2010) (**"EB-2009-0408"**). See the Authorities at Tab 9.

treatment of tax losses arising from the unregulated business of a different division within the same corporation. In that decision, the Board stated:

> The pre-2007 expenses and losses of GLPL's unregulated businesses were borne by GLPL's shareholder, not ratepayers. It would be fundamentally unfair to take such tax losses into account when setting rates for regulated service. To abandon the stand alone principle in this case would give rise to the inappropriate result that rates for regulated service would be affected by the income or loss of a non-regulated business.[228]

Fairness in ratemaking requires adherence to the principle that a party who bears a cost should be entitled to any related tax savings or benefits. The concept is "benefits follow costs". If the ratepayer does not bear the cost, but nevertheless receives the benefit of the related tax savings, then the ratepayer achieves an unfair "double dip" result.

In RP-2004-0188, the Board also considered application of both the "stand-alone" and "benefits follow costs" principles.[229] In that case, the Board was dealing with the consequences of the introduction of the PILS regime, which provided that all tax-exempt distribution utilities were deemed to acquire their assets at fair market value as of October 1, 2001. As a consequence of this "fair market value bump" ("**FMV Bump**"), the distributors became entitled to increased deductions in computing their income subject to PILS. No adjustments to rate base were made for regulatory purposes. The Board expressly stated that, because rates are based on book value and not market value, application of the stand-alone principle would disregard the FMV Bump.

The Board went on to apply the stand-alone principle to those facts and stated, "[h]owever, the shareholder has not incurred any cost related to the change in value for tax purposes … so the

[228] EB-2009-0408 at Pages 9-10 [emphasis added]. See the Authorities at Tab 9.

[229] RP-2004-0188, "2006 Electricity Distribution Rate Handbook", *Report of the Board* (11 May 2005) (**"RP-2004-0188"**). See the Authorities at Tab 10.

"benefits follow costs" principle is not applicable."[230] Instead, the Board found that when distributors entered into the PILS regime, the tax or PILS saving arising from the FMV Bump would be provided to ratepayers. However, on exiting the PILS scheme, the Board agreed that the ratepayers, who had benefitted from the FMV Bump tax saving, should also remain responsible for subsequent recapture. A balance was therefore struck. Disadvantage was not caused to either the shareholder or the ratepayer, and balance was achieved in the long term.[231]

(b) "Taxation" under the *Electricity Act*

The *1996 Report of the Advisory Committee on Competition in Ontario's Electricity System*, which recommended wholesale and retail competition for the supply of Ontario's electricity, recognized the need for a level playing field between publicly-owned operators and private sector operators. To that end, it recommended, among others things, that publicly-owned operators participating in the electricity market should make payments to the Ontario Government equivalent to the provincial and federal income taxes payable by private sector companies. The Ontario Government's 1997 White Paper, *Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario,* adopted that recommendation.

Consequently, amendments were made to the *Electricity Act*[232], which imposed on tax-exempt entities in the electricity sector an obligation to make PILS of the federal and provincial taxes that the entities would have paid if they had not been exempt from tax. Regulations to the *Electricity Act* set out specific rules for the calculation of PILS payable by such tax-exempt entities.

[230] RP-2004-0188 at Page 56. See the Authorities at Tab 10.
[231] RP-2004-0188 at Pages 56-57. See the Authorities at Tab 10.
[232] SO 1998, c 15, Sch A.

In the case of Hydro One, sections 89 and 90 of the *Electricity Act* imposed on it the obligation to pay PILS to the Ontario Electricity Financial Corporation ("**OEFC**") equivalent to the federal and provincial taxes that it would have paid as a taxable entity.

(c) Federal and Provincial Corporate Income Tax

Subsection 149(1) of the ITA exempts certain corporations from the payment of federal tax. Prior to its IPO, Hydro One was exempt from tax under subsection 149(1) of the ITA.

Where a corporation is exempt from tax under subsection 149(1) of the ITA, it will also be exempt from Ontario corporate income taxes pursuant to subsection 27(2) of the OTA.

Paragraph 149(10)(b) of the ITA provides that when a corporation becomes or ceases to be exempt from tax, it is deemed to dispose of its assets for an amount equal to their fair market value, and to have reacquired the assets at a cost equal to that fair market value. Where the tax basis of a corporation's assets is stepped up, it will be able to reduce its income in subsequent years through increased capital cost allowance or "depreciation" claims.

Since a corporation's taxable income under the OTA is the corporation's taxable income as determined for the purposes of the ITA, paragraph 149(10)(b) is applicable for both federal and provincial purposes.

Unless a corporation is operating at a loss, the increased capital cost allowance claims associated with a tax basis bump will result in a reduced tax liability under the ITA and OTA.

(d) Departure Tax

The bump in the tax basis of a corporation's assets to fair market value would result in an uneven "tax" playing field if tax exempt entities paying PILS under the *Electricity Act* could have exited that system and become subject to tax under the ITA and OTA with a cost-free step up in the tax basis of their assets.

However, this step-up in tax basis does not come without a cost in the case of a corporation liable to PILS under the *Electricity Act.* Such a corporation will pay "departure" PILS on recaptured depreciation and capital gains as determined under the rules in paragraph 149(10)(b) of the ITA.[233]

Section 16.1 of the PILS Regulation contains the applicable rules when a corporation ceases at any time to be exempt under subsection 149(1) of the ITA and subsection 27(2) of the *Taxation Act, 2007* (Ontario). It provides, in part:

> (2) The taxation year of the corporation is deemed to end immediately before the time that the corporation ceases to be exempt under subsection 149 (1) of the Federal Act.
>
> (3) Subject to subsections (4) and (5), the corporation shall pay the amount determined under sections 89 and 90 of the Act calculated by reference to the deemed disposition under paragraph 149(10)(b) of the Federal Act (as that paragraph applies for the purposes of determining the amount payable under sections 89 and 90 of the Act).
>
> …
>
> (5) The corporation is not required to pay the amount described in subsection (3) if both of the following conditions are satisfied:
>
> > 1. The corporation ceases to be exempt from the payment of tax under the Federal Act as a result of a lawful distribution to the public of shares of the corporation or a related corporation pursuant to a prospectus, registration statement or similar document filed with and, if required by law, accepted for filing by a public authority in Canada under the laws of Canada or of a province. The distribution must be the first distribution to the public of shares of the corporation or related corporation.

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[233] Pursuant to the 2015 Ontario Budget, amendments were made to the Ontario regulations to the *Electricity Act* such that corporations that cease to be tax exempt after December 31, 2015 and before January 1, 2019 are not liable for departure PILS on capital gains arising from the application of paragraph 149(1)(b) of the ITA. See PILS Regulation, s 16.1(8).

> 2. With the consent of the Minister, the corporation pays to the Financial Corporation an amount that, in the Minister's opinion, reasonably approximates the additional amounts, if any, that would be payable by the corporation under sections 89 and 90 of the Act if the corporation were required, but for this subsection, to pay the amount described in subsection (3)

Thus, the step-up in the tax basis of Hydro One's assets that occurred under paragraph 149(10)(b) of the ITA as part of its IPO is very different from the "costless" step-up in tax basis that Hydro One obtained when it acquired Ontario Hydro's assets.

On a consolidated basis, Hydro One paid $2.271 billion of departure PILS. As will be discussed below, this amount was a real, actual cost and tax liability. It was incurred. The tax liability incurred by Hydro One was funded by its shareholder, in connection with the step-up in the tax basis of its assets when it ceased to be exempt from tax on the IPO because of the combined operation of the *Electricity Act*[234] and Paragraph 149(10)(b) of the ITA. However, the incurrence of the tax cost and the funding of that cost are two separate and discrete matters.

While the Ontario Hydro assets transferred to Hydro One pursuant to Section 116 of the *Electricity Act* were deemed to have been acquired by Hydro One at fair market value pursuant to Section 9 of the PILS Regulation, there was no tax or other charge imposed on Hydro One in connection with this step-up in the basis of the assets.

Ontario ratepayers therefore have had the benefit of the earlier "tax free" step-up in the basis of Hydro One's assets as the tax savings from that FMV bump, being reduced taxes because of higher capital cost allowance claims, were reflected in the income tax amounts recovered in revenue requirements approved by the Board. Now that Hydro One is exiting the PILS regime, recapture applies and these tax savings have essentially been reversed through the deemed disposition of Hydro One's assets under Paragraph 149(10)(b) of the ITA. Generally, to the

[234] *Electricity Act,* ss 89-90; PILS Regulation, s 16.1.

extent that the fair market value of a depreciable asset was greater than its undepreciated capital cost, the capital cost allowance will have been recaptured and subject to PILS upon Hydro One exiting the PILS regime.

(e) Facts Justifying Application of the Stand-alone and Cost Follow Benefits Principles

As discussed below, Hydro One's proposed rate treatment of the Departure Tax cost and resulting deferred tax asset is supported by the following: (i) the shareholder's decision to sell its ownership interests caused the company to incur the Departure Tax; (ii) incurrence of this cost by the company has no relationship to the provision of regulated transmission services provided to ratepayers; (iii) the Departure Tax was real cost incurred by Hydro One; and (iii) Hydro One funded the Departure Tax liability entirely by its shareholder and not ratepayers.

(i) Shareholder's Ownership Interest Disposition Caused Hydro One to Incur the Departure Tax

The evidence before the Board is that the initial public offering process precipitated Hydro One having to pay the Departure Tax and recognition of the deferred tax asset.[235] But for the shareholder's decision to reorganize and sell its ownership interests in HOL (the ultimate parent of Hydro One) the Departure Tax liability would not have arisen. Had the shareholder not made this decision, Hydro One would have remained under the PILS regime and there would have been no Departure Tax liability arising.

The obligation to pay the Departure Tax arose from two sequential steps in the reorganization of Hydro One Inc. (**"HOI"**) and at the time leading up to the initial public offering.[236] The first step

[235] Exhibit J2.9.
[236] Exhibit J11.10.

occurred on October 29, 2015, when HOL, a wholly owned subsidiary of the Province of Ontario (**"Province"**) entered into agreements to sell 15% of its outstanding common shares to the underwriters for distribution to the public. This action caused HOL to cease to be exempt from federal income tax. The second step occurred on October 31, 2015 when HOL acquired all of the issued and outstanding shares of HOI from the Province. This action caused HOI and its subsidiaries, including Hydro One, to no longer be exempt from federal income tax, thereby triggering the obligation of HOI and its subsidiaries to pay the Departure Tax to the OEFC.

The only possible way for these sequential steps to have taken place was through oversight and direction by the Province as owner of the outstanding shares in HOI and HOL. Had the Province not taken these steps, the Departure Tax obligation would not have been incurred by HOI and its subsidiaries.

(ii) No Relationship Between the Incurrence of the Departure Tax Cost and The Provision of Transmission Regulated Services

The obligation and payment of the Departure Tax arose due to circumstances entirely unrelated to the costs and activities that Hydro One incurs to provide transmission regulated services.[237] The Departure Tax liability and payment was caused by the shareholder's decision to sell its ownership interests in HOL, which triggered the operative provisions of the *Electricity Act* and the corresponding Regulations. That is why Hydro One has not included the recovery of the Departure Tax payment in its regulated rate revenue requirement.

Non-inclusion of the Departure Tax liability in the applied-for rates revenue requirement is consistent with the stand-alone principle. Moreover, non-inclusion provides for the equivalent result described in RP-2004-0188 as it concerns rate-payers being obligated to recover the

[237] Exhibit J2.9.

recapture of an FMV bump. If the deferred tax asset was recognized in the rates revenue requirement recovered from ratepayers then a “double dip” would be created. Ratepayers have historically received the CCA benefit. Exiting the PILS scheme (as opposed to the entry into it) gives rise to the recapture of this historical benefit. What RP-2004-0188 contemplates is that ratepayers must cover the costs giving rise to that recapture (i.e. payment of the Departure Tax) in order to receive the FMV bump. Such a result would have obvious and material adverse effects to rates.

Acknowledging that the Departure Tax liability bears no relationship to the costs Hydro One incurs for the provision of transmission regulated services, the recapture impact is avoided entirely and ratepayers are kept whole by the Board acknowledging that the Departure Tax liability has been incurred by the Company, financed by the shareholder and outside of the rate regulated entity, based on the stand-alone construct. In so doing, the deferred tax asset benefit must also remain outside of the rates revenue requirement so that fairness is maintained and the principles of stand-alone and “benefits follow costs” are applied.

(iii) The Departure Tax was a real cost incurred by Hydro One

The evidence before the Board is that Hydro One paid the Departure Tax amount of $2.271 billion to the OEFC on November 4, 2015.[238] The payment was real. Wire transfer information and Hydro One’s bank statements provide indisputable evidence that the cost was real and actually incurred.[239]

[238] Exhibit J11.10.
[239] Exhibit J11.16, Attachment 1.

(iv) HOL incurred a $2.6 billion tax liability funded entirely by the shareholder

In order to fund payment of the Departure Tax liability, recapitalization of HOI and its subsidiaries including Hydro One, was necessary. As noted in Exhibits J11.11 and J11.14 several transactions occurred on November 4, 2015, the effect of which was that Hydro One received cash proceeds from the trickle down recapitalization and in the amount of $2.271 billion. This investment was reported in the Unconsolidated Financial Statements of HOI and Hydro One for the period ending October 31 and November 4, 2015. At Page 35 of the HOL Financial Statements, reference is made that Hydro One used the proceeds of the share subscription to pay the Departure Tax.[240] These transactions and method of financing the Departure Tax liability was also subsequently recorded in HOL's 2015 Annual Report and audited financial statements.[241] The unassailable evidence is that a real cost was incurred by Hydro One and its shareholder in carrying out this recapitalization financing requirement.

Recall Mr. Vels's testimony that while other financing options existed, namely, raising debt or seeking recovery from rate-payers, the choice made by Hydro One was an equity injection and recapitalization.[242] This decision was made because the other available alternatives would have adversely affected the financial well-being of the Company, which would be damaging to both the Company and its shareholder, particularly given the intention of the shareholder to sell its interests to the public.

The recapitalization of the Company by the shareholder following the payment of the Departure Tax by each of the HOL's legal entities did not increase the book value or equity value of HOL; it reinstated the value of HOL to what it was immediately prior to the payment of the Departure

[240] Exhibit J11.16, Attachment 2, Page 35.

[241] Notes 7 and 18 to HOL's 2015 Consolidated Financial Statements, found at Pages 68 and 91-92 of Exhibit A8-01-01.

[242] Transcript Volume 1, Page 29, Line 25 to Page 35, Line 23; Transcript Volume 11, Page 15, Line 21 to Page 78, Line 28.

Tax.[243] The shareholder incurred a cost to preserve the market value of the company.[244] The shareholder's ultimate disposition of its ownership interests was not the source of funds used to finance the necessary recapitalization. That is because the cost to recapitalize the company occurred before the time at which the shareholder ultimately sold shares to the public under the terms of the initial public offering. The only relationship between the recapitalization costs and proceeds from the initial public offering was the shareholder's desire to ensure that the Company's valuation at the time of the IPO was not harmed by the Company incurring the Departure Tax liability.

(f) Applying Rate Making Principles to the Present Circumstances

The evidence before the Board demonstrates that costs incurred by Hydro One for the Departure Tax do not pertain to the provision of regulated transmission service. The provision of regulated transmission services is not what caused Hydro One to incur the Departure Tax costs. The deferred tax asset similarly has not resulted from the provision of regulated transmission services. But for the IPO and the related incurrence of the Departure Tax, there would be no deferred tax asset. Given this, Hydro One submits it would be unreasonable to allocate any of the Departure Tax costs or the deferred tax asset benefits to the regulated transmission services and the rates charged for such services as determined through calculation of the rates revenue requirement.

The evidence before the Board demonstrates that Hydro One has incurred a real cost. Ratepayers have not borne these expenses. Consistent with the EB-2009-0408 Decision, there is good reason to consistently find that cost causation and stand-alone principles should be applied in the same manner. It is appropriate to have ratepayers remain unaffected by the

[243] Exhibit J1.3.
[244] Exhibit J1.3.

transactions that gave rise to the Departure Tax payment and the deferred tax asset benefits because none of these matters relate at all to the provision of rate regulated transmission services.

With regard to the costs follow benefits principle, the present circumstances are distinguishable from those arising in RP-2004-0188. Here, there should be no ratepayer windfall given that Hydro One and the Province have incurred real costs for the actual payment and the financing of the Departure Tax. As the costs are real and they do not pertain to regulated services, benefits arising from those costs should accrue to the paying party.

[245] Handbook, Page 2; RRF Report. See the Authorities at Tab 1.

School Energy Coalition (SEC) INTERROGATORY #4

Interrogatory:

[Ex. A/2/1, p. 3] Please provide the full calculations supporting Table 2.

Response:

Please refer to Attachment 1. Hydro One has noted a revision is required to Table 2 documentation pertaining to a correction to the DRC rate applicable to OPDC. The revision is limited to a change for the GS<50kw, Change In Total Bill, from -0.23% to -0.22%. The updated Table is provided below.

Table 2: Bill Impacts for OPDC Customers

Rate Class[1]	Change in Distribution Delivery Rates	Change in Total Bill (%)
Residential	(0.92%)	(0.20%)
General Service less than 50 kW	(1.08%)	(0.22%)
General Service 50 to 999 kW	(0.97%)	(0.07%)

[1] The proposed 1% rate reduction does not apply to the other rate classes.

	Residential					
	Volume	**Current Rates**	**Current Charges ($)**	**Rates as per Acquisition Agreement**	**Charges as per Acquisition Agreement ($)**	**% Change**
Monthly Consumption (kWh)	**750**					
Total Loss Factors	**1.0561**					
TOU - Off Peak Consumption	488	0.087	$42.41	0.087	$42.41	
TOU - Mid Peak Consumption	128	0.132	$16.83	0.132	$16.83	
TOU - On Peak Consumption	135	0.180	$24.30	0.180	$24.30	
Total: Commodity			**$83.54**		**$83.54**	**0.00%**
DX Fixed Charge ($)	1	17.68	$17.68	17.50	$17.50	
DX Fixed Charge Rate Riders ($)	1	-1.15	-$1.15	-1.15	-$1.15	
DX Vol. Charge ($/kWh)	750	0.0127	$9.53	0.0126	$9.45	
DX Low Voltage Charge ($/kWh)	750	0.0006	$0.45	0.0006	$0.45	
DX Vol. Rate Riders ($/kWh)	750	-0.0015	-$1.13	-0.0015	-$1.13	
Distribution Base Rates Only			**$27.66**		**$27.40**	**-0.92%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	
Cost of Losses ($/kWh)	42	0.1114	$4.69	0.1114	$4.69	
Distribution Pass-through Charges			**$5.48**		**$5.48**	**0.00%**
Total: Distribution			**$33.13**		**$32.88**	**-0.77%**
TX-Network ($/kWh)	792	0.0054	$4.28	0.0054	$4.28	
TX-Connection ($/kWh)	792	0.0041	$3.25	0.0041	$3.25	
Total: Transmission			**$7.52**		**$7.52**	**0.00%**
WMSC ($/kWh)	792	0.0036	$2.85	0.0036	$2.85	
RRRP ($/kWh)	792	0.0013	$1.03	0.0013	$1.03	
OESP ($/kWh)	792	0.0011	$0.87	0.0011	$0.87	
SSA ($)	1	0.25	$0.25	0.25	$0.25	
Total: Regulatory			**$5.00**		**$5.00**	**0.00%**
Total Bill (Before Taxes)			$129.20		$128.95	
HST		13%	$16.80	13%	$16.76	
Total Bill (Including HST)			**$146.00**		**$145.71**	**-0.20%**

	General Service Less Than 50kW					
	Volume	**Current Rates**	**Current Charges ($)**	**Rates as per Acquisition Agreement**	**Charges as per Acquisition Agreement ($)**	**% Change**
Monthly Consumption (kWh)	**2,000**					
Total Loss Factors	**1.0561**					
TOU - Off Peak Consumption	1,300	0.087	$113.10	0.087	$113.10	
TOU - Mid Peak Consumption	340	0.132	$44.88	0.132	$44.88	
TOU - On Peak Consumption	360	0.180	$64.80	0.180	$64.80	
Total: Commodity			**$222.78**		**$222.78**	**0.00%**
DX Fixed Charge ($)	1	37.42	$37.42	37.05	$37.05	
DX Fixed Charge Rate Riders ($)	1	7.48	$7.48	7.48	$7.48	
DX Vol. Charge ($/kWh)	2,000	0.0165	$33.00	0.0163	$32.60	
DX Low Voltage Charge ($/kWh)	2,000	0.0006	$1.20	0.0006	$1.20	
DX Vol. Rate Riders ($/kWh)	2,000	-0.0064	-$12.80	-0.0064	-$12.80	
Distribution Base Rates Only			**$71.62**		**$70.85**	**-1.08%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	
Cost of Losses ($/kWh)	112	0.1114	$12.50	0.1114	$12.50	
Distribution Pass-through Charges			**$13.29**		**$13.29**	**0.00%**
Total: Distribution			**$84.91**		**$84.14**	**-0.91%**
TX-Network ($/kWh)	2,112	0.0045	$9.50	0.0045	$9.50	
TX-Connection ($/kWh)	2,112	0.0038	$8.03	0.0038	$8.03	
Total: Transmission			**$17.53**		**$17.53**	**0.00%**
WMSC ($/kWh)	2,112	0.0036	$7.60	0.0036	$7.60	
RRRP ($/kWh)	2,112	0.0013	$2.75	0.0013	$2.75	
OESP ($/kWh)	2,112	0.0011	$2.32	0.0011	$2.32	
DRC ($/kWh)	2,000	0.0049	$9.80	0.0049	$9.80	
SSA ($)	1	0.25	$0.25	0.25	$0.25	
Total: Regulatory			**$22.72**		**$22.72**	**0.00%**
Total Bill (Before Taxes)			$347.94		$347.17	
HST		13%	$45.23	13%	$45.13	
Total Bill (Including HST)			**$393.17**		**$392.30**	**-0.22%**

	General Service 50 to 4,999 kW					
	Volume	**Current Rates**	**Current Charges ($)**	**Rates as per Acquisition Agreement**	**Charges as per Acquisition Agreement ($)**	**% Change**
Monthly Consumption (kWh)	**73,000**					
Peak (kW)	**100**					
Total Loss Factors	**1.0561**					
Commodity Charges	77,095	0.103	$7,940.82	0.103	$7,940.82	
Total: Commodity			**$7,940.82**		**$7,940.82**	**0.00%**
DX Fixed Charge ($)	1	340.60	$340.60	337.19	$337.19	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	
DX Vol. Charge ($/kW)	100	3.5825	$358.25	3.5467	$354.67	
DX Low Voltage Charge ($/kW)	100	0.2230	$22.30	0.2230	$22.30	
DX Vol. Rate Riders ($/kW)	100	-2.3585	-$235.85	-2.3585	-$235.85	
Distribution Base Rates Only			**$721.15**		**$714.16**	**-0.97%**
Total: Distribution			**$485.30**		**$478.31**	**-1.44%**
TX-Network ($/kW)	100	1.9991	$199.91	1.9991	$199.91	
TX-Connection ($/kW)	100	1.5382	$153.82	1.5382	$153.82	
Total: Transmission			**$353.73**		**$353.73**	**0.00%**
WMSC ($/kWh)	77,095	0.0036	$277.54	0.0036	$277.54	
RRRP ($/kWh)	77,095	0.0013	$100.22	0.0013	$100.22	
OESP ($/kWh)	77,095	0.0011	$84.80	0.0011	$84.80	
DRC ($/kWh)	73,000	0.0049	$357.70	0.0049	$357.70	
SSA ($)	1	0.25	$0.25	0.25	$0.25	
Total: Regulatory			**$820.52**		**$820.52**	**0.00%**
Total Bill (Before Taxes)			$9,600.37		$9,593.38	
HST		13%	$1,248.05	13%	$1,247.14	
Total Bill (Including HST)			**$10,848.42**		**$10,840.52**	**-0.07%**

	Change in Base Distribution Rates (%)	Change in Total Bill (%)
Residential	-0.92%	-0.20%
General Service Less Than 50kW	-1.08%	-0.22%
General Service 50 to 4,999 kW	-0.97%	-0.07%

Attachment X: Determination of Rate Riders as per Acquisition Agreement

Rate Class	Distribution Charges	OPDC Distribution Rates Effective May 1, 2016 (EB-2015-0024)	Proposed Rate Riders per Acquisition Agreement
		A	B = A*(-0.01)
Residential	Service Charge ($)	17.68	-0.18
	Distribution Volumetric Rate ($/kWh)	0.0127	-0.0001
General Service Less Than 50kW	Service Charge ($)	37.42	-0.37
	Distribution Volumetric Rate ($/kWh)	0.0165	-0.0002
General Service 50 to 4,999 kW	Service Charge ($)	340.6	-3.41
	Distribution Volumetric Rate ($/kW)	3.5825	-0.0358

School Energy Coalition (SEC) INTERROGATORY #5

Interrogatory:

Please confirm that the following correctly sets out approved distribution rates for OPDC and Hydro One for 2016 and the resulting annual distribution bills. The monthly and volumetric charges are from approved rate orders, and the average volumes are from the 2015 OEB Yearbook.

Hydro One vs. Orillia Annual Distribution Bills Comparison

Orillia Class and Average Load per Cust.	***Billing Component***	***Orillia 2016 Rates***		***Hydro One 2016 Rates (Urban)***		***Hydro One 2016 Rates (Medium Density R1)***	
Residential 736	Monthly	17.68	$212.16	22.29	$267.48	30.11	$361.32
	Volume	0.0127	$112.17	0.0162	$143.08	0.0299	$264.08
	Total Bill		$324.33		$410.56		$625.40
GS<50KW 2723	Monthly	37.42	$449.04	22.28	$267.36	27.94	$335.28
	Volume	0.0165	$539.15	0.0252	$823.44	0.0563	$1,839.66
	Total Bill		$988.19		$1,090.80		$2,174.94
GS>50KW 171	Monthly	340.6	$2,946.60	88.26	$1,059.12	84.35	$1,012.20
	Volume	3.5825	$8,126.33	8.6129	$17,673.67	14.9906	$30,760.71
	Total Bill		$11,072.93		$18,732.79		$31,772.91

Response:

Hydro One confirms that the base distribution rates (excluding riders) and calculations shown for the Residential and GS<50kW class are correctly set out. For the GS>50kW class the rates are correctly set out, but the calculation of the Orillia annual charges is not correct. Please see the corrected calculations below:

	Billing Component	***Orillia 2016 Rates***	
GS>50KW	Monthly	340.6	$4,087.20
171	Volume	3.5825	$7,351.29
	Total Bill		**$11,438.49**

As Hydro One has noted in the Application, rates for OPDC customers will be determined and approved at a future rate hearing, consistent with OEB policies.

School Energy Coalition (SEC) INTERROGATORY #6

Interrogatory:

[Ex. A/2/1, p. 5] Please provide a dollar estimate of the aggregate "small price benefit" that will be enjoyed by Hydro One's existing customers. Please confirm that it is OPDC's existing customers that will bear the cost of that small price benefit.

Response:

Hydro One has not calculated an exact benefit to Hydro One's existing customers. The benefit will arise from spreading fixed costs over a larger customer base upon rebasing of the combined entity. Future rate applications, post-deferral period, will review the allocation of these costs for rate-making purposes to all Hydro One customers, including former OPDC customers. The overall result of this transaction is that the cost structures will be lower than they otherwise would have been in absence of the transaction.

School Energy Coalition (SEC) INTERROGATORY #7

Interrogatory:

[Ex. A/2/1, p. 17] Please provide the current Distribution System Plan of OPDC approved by the Board. If there is no such approved DSP, please advise when that plan will be filed, and the process that is proposed for review of that plan by the Board. Also, if there is no approved DSP, please provide the capital expenditures forecast on which the status quo estimates in Table 1 on page 2 were based.

Response:

OPDC does not currently have an approved DSP. In 2022, when Hydro One expects to file its rates application for 2023 and subsequent years, Hydro One will prepare a consolidated Distribution System Plan that will include all necessary and relevant information for serving the assets of OPDC. On November 19, 2016, Hydro One provided a letter to the OEB in response to EB-2014-0138, outlining a similar proposal for the recently acquired and integrated LDCs.

For the Table 1 status quo capital expenditure forecast, refer to Exhibit I, Tab 1, Schedule 2, Attachment 1.

School Energy Coalition (SEC) INTERROGATORY #8

Interrogatory:

[Ex. A/2/1, p. 18] Please provide details of all materials impacts that will arise because of the change from MIFRS to US GAAP as proposed, including but not limited to changes in depreciation rates, changes in capitalization rules, and changes in the amounts added to or deducted from rate base annually until the costs for the OPDC area are next considered by the Board in a rebasing.

Response:

At this time Hydro One anticipates that the following areas will be impacted as a result of OPDC transitioning from IFRS to US GAAP:

(a) Property, Plant & Equipment
   a. Depreciation
   b. Capitalization
   c. Accounting for customer contributions
(b) Post-retirement benefits & related deferred taxes.

Hydro One is currently not in a position to provide details of such adjustments as a full assessment of IFRS to USGAAP transition for OPDC has not yet been completed.

School Energy Coalition (SEC) INTERROGATORY #9

Interrogatory:

[Ex. A/2/1, p. 19] Please provide the most recent agreements between OPDC and each of its unregulated affiliates, and describe how, if at all, the arrangements with those affiliates will change after the completion of the transactions proposed.

Response:

Please refer to Attachment 1 for the current agreement between OPDC and OPGC, being the only agreement with an unregulated affiliate of which Hydro One is aware. Attachment 2 is provided to show that certain exemptions from compliance with the Affiliates Relationship Code were granted with respect to the terms of this agreement. Hydro One has not yet determined how these arrangements might change after completion of the proposed transactions but notes that the agreement may be terminated on notice by either party. Additionally, Hydro One notes that on completion of the acquisition of OPDC by Hydro One, OPGC will no longer be an affiliate of OPDC.

SERVICES AGREEMENT

BETWEEN

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

AND

ORILLIA POWER GENERATION CORPORATION (OPGC)

As of
JANUARY 1, 2001

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SERVICES AGREEMENT

THIS AGREEMENT is made as of January 1, 2001

BETWEEN:

ORILLIA POWER DISTRIBUTION CORPORATION, a corporation incorporated under the laws of the Province of Ontario ("OPDC"),

- and -

ORILLIA POWER GENERATION CORPORATION, a corporation incorporated under the laws of the Province of Ontario ("OPGC").

THIS AGREEMENT WITNESSES, that, in consideration of the convenants and agreements herein contained, the parties hereto agree as follows:

ARTICLE 1 – GENERAL

1.01 **Services Provided by OPDC to OPGC**

Subject to the terms and conditions hereof, OPGC (The Corporation) shall retain OPDC (The Service Provider) to carry out services and OPDC shall render the following services to OPGC:

(a) office rent and building maintenance including janitorial services, snow plowing, lawn care, major and minor repairs;

(b) purchasing including procurements at best price, order tracking, delivery of operating and capital items, payment processing and vendor management;

(c) stores management including maintaining stock levels at most efficient levels, issuing and receiving, maintenance of inventory management system and disposition of excess assets;

(d) safety monitoring including the development of policies and procedures, training (awareness and procedures);

(e) environmental compliance monitoring including development of policies and procedures, training (awareness and procedures), regulatory reporting, government liaison and site inspections;

(f) human resources administration including development of policies and procedures, union relations and negotiations, personnel file management and management of employee benefit plans;

(g) bookkeeping including provision of statutory financial and regulatory reporting, management reporting and financial systems administration;

(h) payroll including the maintenance of payroll records and payroll system, calculation of pay and payroll deductions and facilitation of payroll payments;

(i) fleet management including the maintenance of all vehicles in working condition, major and minor repairs, regulatory reporting, expense tracking and fleet management system administration;

(j) financial management including cash administration, investments and debt management, internal audit services and development of financial and accounting policies and procedures;

(k) tax administration including compliance, regulatory reporting, planning, audit reviews and exposure management; and

(l) information technology including provision and management of systems, system and hardware support services, major and minor repairs, development and policies and procedures, and monitoring of information technology developments;

(m) engineering services;

(n) monitoring status of generating facilities using SCADA technology; and

(o) such other services as may from time to time be agreed upon between the parties.

1.02 **<u>Services Provided by OPGC to OPDC</u>**

Subject to the terms and conditions hereof, OPDC (The Corporation) shall retain OPGC (The Service Provider) to carry out services and OPGC shall render the following services to OPDC:

(a) Until the opening of the electricity market is proclaimed (May 1, 2002), the sale of all energy produced (in kWh) by Swift, Minden and Matthias waterpower generation plants and the Diesel plant to the distribution corporation. Once the market is declared open, all energy produced (in kWh) by Matthias and Diesel plants, being physically embedded within the distribution system, to be sold to the distribution corporation on behalf of the City of Orillia customers;

(b) maintenance of substations including major and minor repairs;

(c) staff supervision and technical support of monitoring facilities;

(d) coordination of building maintenance and security; and

(e) such other services as may from time to time be agreed upon between the parties.

1.03 **Term of Agreement**

The provision of services by the Service Provider to the Corporation hereunder shall commence January 1, 2001 and shall continue until terminated by the parties hereto as set forth in Article 5 hereof.

The terms of this agreement may be opened for re-negotiation within 60 days of the anniversary date with the consent of both parties. The new terms would be negotiated to take effect on the anniversary date.

ARTICLE 2 – REMUNERATION OF SERVICE PROVIDER

2.01 **Fee for Services**

The Corporation shall pay the Service Provider for the services provided under this Agreement at a fee at the rate of cost plus a reasonable rate of return on invested capital as determined by the parties, provided that such fee for services at the above-noted rate shall be reviewed by the parties at the option of either party.

2.02 **Reasonable Rate of Return**

Reasonable rate of return on invested capital will normally be defined as the higher of OPDC's rate of return approved by the Ontario Energy Board (OEB) rounded to the nearest 1% (currently 10%) and the prime rate. This rate of return will apply to services provided by either OPDC or OPGC.

2.03 **Expenses**

The Service Provider shall be responsible for all day to day expenses incurred in connection with the services to be provided pursuant to Section 1.01 or 1.02 hereof. However, the Corporation shall reimburse the Service Provider for all extraordinary expenses actually and properly incurred by the Service Provider in the performance of the services hereunder provided that such expenses shall be paid in accordance with the normal practices of the Corporation in force from time to time.

2.04 **Cost Allocation Methodologies**

Different cost allocation methodologies are required depending on the service being provided. Methodologies may be revised from time to time due to changing facts and circumstances. Acceptable methodologies are subject to final approval by the President and Treasurer of Orillia Power Corporation.

Specific methodologies for certain items are outlined below:

(a) for rent and building maintenance outlined in 1.01(a): Costs are allocated based on a reasonable estimate of floor space occupied by the two companies.

(b) for administration services outlined in 1.01(b) to 1.01(l): The labour costs related to staff providing the aforementioned services and other general administrative costs related to running the organization as a whole are allocated to OPDC and OPGC using a percentage determined annually. The allocation is based on a determination of the estimated percentage of time each of the administrative staff would normally spend on activities related to each company.

(c) for engineering services provided by OPDC to OPGC outlined in 1.01(m): All labour time by OPDC staff is charged to OPGC using time sheets. General costs of the engineering department not allocable directly are charged 50% to OPDC and 50% to OPGC.

(d) for SCADA services provided by OPDC to OPGC outlined in 1.01(n): All operations and maintenance costs related to the control centre are to be allocated 50% to OPDC and 50% to OPGC. This percentage is based on a reasonable estimate of time spent by control room staff on activities related to each company.

(e) for energy production supplied to distribution from generation outlined in 1.02(a): Until the market is declared open, each kWh supplied will be priced using the Ontario Energy Board fixed reference price for Standard Supply Service. Once the energy market is open to competition, the price for each kWh supplied will be the Hourly Ontario Energy Price (HOEP) as determined by the spot market.

(f) for substation maintenance outlined in 1.02(b): Labour costs are charged using time sheets. Costs other than labour for maintaining substations are charged directly to OPDC.

2.05 **Invoices**

Payment shall be made to the Service Provider with respect to the fees and expenses referred to in Sections 2.01, 2.02 and 2.03 within 10 days from receipt by the Corporation of proper invoices and vouchers. Invoices will be rendered by the Service Provider to the Corporation either monthly, quarterly or annually. The invoice timing for a particular service (ie. monthly, quarterly or annually) will depend on the materiality of the charge or to ensure administrative ease. What is material will be determined by the Treasurer who is responsible for the financial well being of both entities. As a minimum, all services related to a particular fiscal year will be invoiced as part of that year-end. The Service Provider shall also provide a report annually of all expenses incurred in connection with the provision of services pursuant to Section 1.01 and 1.02 hereof.

ARTICLE 3 – COVENANTS OF SERVICE PROVIDER

3.01 **Services**

The Service Provider shall render performance of the services hereunder to the best of the Service Provider's ability and in a competent and professional manner.

3.02 **Time of Services**

The Service Provider shall devote such of its time and attention to the business of the Corporation as may be agreed to by the Service Provider and the Corporation. The time of service to be provided hereunder by the Service Provider shall be as agreed to from time to time by the Corporation and the Service Provider. Subject to the obligations of the Service Provider hereunder, the Service Provider shall be free to offer services to any other person.

3.03 **Licenses and Permits**

The Service Provider shall be responsible for obtaining all necessary licenses and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulation in connection with the provision of the services hereunder and the Service Provider shall when requested provide the Corporation with adequate evidence of his compliance with this Section 3.03.

3.04 **Rules and Regulations**

The Service Provider shall comply, while on the premises used by the Corporation, with all the rules and regulations of the Corporation from time to time in force which are brought to its notice of which it could be reasonably aware.

3.05 **Insurance**

The Service Provider shall pay for and maintain for the benefit of the Service Provider and the Corporation, with insurers or through the appropriate government department and in an amount and in a form acceptable to the Corporation, appropriate insurance concerning the operations and liabilities of the Service Provider relevant to this Agreement including, without limiting the generality of the foregoing, workers' compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by the Service Provider to any employees of the Service Provider and public liability and property damage insurance.

3.06 **Indemnity**

The Service Provider shall indemnify and save the Corporation harmless from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which the Corporation or its officers, employees or agents may suffer as a result of the negligence of the Service Provider and in the performance or non-performance of this Agreement.

3.07 **Non-disclosure**

The Service Provider shall not (either during the term of this Agreement or at any time thereafter) disclose any information relating to the private or confidential affairs of the Corporation or relating to any secrets of the Corporation to any person other than with the consent of the Corporation.

ARTICLE 4 – TERMINATION

4.01 **Termination by Corporation or Service Provider for Cause**

The Corporation or the Service Provider may terminate this Agreement at any time in the event of the failure of the other party to comply with any of the provisions hereunder upon such other party being notified in writing by the party alleging such failure and failing to remedy such failure within 30 days of receiving such notice.

4.02 **Termination by Corporation or Service Provider on Notice**

The Corporation or Service Provider may terminate this Agreement upon the giving of 60 days written notice to the other party. Notwithstanding the foregoing, the Corporation may terminate this Agreement immediately upon paying to the Service Provider 60 days fee for services in lieu of such notice.

4.03 **Provisions which Operate Following Termination**

Notwithstanding any termination of this Agreement for any reason whatsoever and with or without cause, the provisions of Sections 3.06 and 3.07 and any other provisions of this Agreement necessary to give efficacy thereto shall continue in full force and effect following any such termination.

ARTICLE 5 – ARBITRATION

5.01 **Arbitration of Disputes**

Any disputes arising between the parties relating to the interpretation of any provision of this Agreement or other matters which under the provision of this Agreement are referred to arbitration shall be settled by arbitration in accordance with the provisions of Section 5.02.

5.02 **Appointment of Arbitrator and Arbitration Procedures**

(a) In the event of disagreement, litigation or dispute with respect to the interpretation, application or execute of one or the other of the provisions of this Agreement the parties hereto renounce their right to institute legal proceedings and undertake to submit such disagreement, litigation or dispute to the final decision pursuant to Arbitration in accordance with Schedule "A" hereto.

(b) The fees and disbursements of the arbitrator shall be shared equally by the parties to this Agreement.

(c) The arbitration provided for in this Agreement is subject to the provisions of the Arbitration Act (Ontario), to the extent that such provisions are not incompatible herewith.

ARTICLE 6 – INTERPRETATION AND ENFORCEMENT

6.01 **Sections and Headings**

The divisions of this Agreement into Articles and Sections and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms of "this Agreement", "hereof", "hereunder", and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof and include any agreement or instrument supplemental or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

6.02 **Extended Meanings**

In this Agreement words importing the singular number only include the plural and *vice versa*, words importing any gender include all genders and words importing persons include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and *vice versa*.

6.03 **Benefit of Agreement**

This Agreement shall enure to the benefit of and be binding upon successors and assigns of the Service Provider and the Corporation, respectively.

6.04 **Entire Agreement**

This Agreement constitutes the entire agreement between the parties with respect to the subject matter hereof and cancels and supersedes any prior understandings and agreements between the parties hereto with respect thereto. There are no representations, warranties, forms, conditions, undertakings or collateral agreements, express implied or statutory between the parties other than as expressly set forth in this Agreement.

6.05 **Amendments and Waivers**

No amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the parties hereto. No waiver of any breach of any term or provision of this Agreement shall be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

6.06 **Assignment**

Except as may be expressly provided in this Agreement, neither party hereto may assign his or its rights or obligations under this Agreement without the prior written consent of the other party hereto.

6.07 **Severability**

If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of any such provision and all other provisions hereof shall continue in full force and effect.

6.08 **Notices**

Any demand, notice or other communication to be made or given in connection with this Agreement shall be made or given in writing and may be made or given by personal delivery or by registered mail addressed to the recipient as follows:

Orillia Power Distribution Corporation
360 West St. S., P.O. Box 398
Orillia ON L3V 6J9
Attn: Pat Hurley

Orillia Power Generation Corporation
360 West St. S., P.O. Box 398
Orillia ON L3V 6J9
Attn: John Mattinson

or any other such address or individual as may be designated by notice by either party to the other. Any demand, notice or other communication made or given by personal delivery shall be conclusively deemed to have been given on the day of actual delivery thereof and, if made or given by registered mail, on the 5th day, other than a Saturday, Sunday or statutory holiday in Ontario, following the deposit thereof in the mail. If the party giving any demand, notice or other communication knows or ought reasonably to know of any difficulties with the postal system which might affect the delivery of the mail, any such demand, notice or other communication shall not be mailed but shall be made or given by personal delivery.

6.09 **Further Assurances**

Each party must from time to time execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

6.10 **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.

6.11 **Attornment**

For the purpose of all legal proceedings this Agreement shall be deemed to have been performed in the Province of Ontario and, subject to Article 5 of this Agreement, the courts of the Province of Ontario shall have jurisdiction to entertain any action arising under this Agreement. Subject to Article 5 of this Agreement, the Corporation and the Service Provider each hereby attorns to the jurisdiction of the courts of the Province of Ontario provided that nothing herein contained shall prevent the Corporation from proceeding at its election against the Service Provider in the courts of any other province or country.

IN WITNESS WHEREOF the parties have executed this Agreement.

ORILLIA POWER DISTRIBUTION CORPORATION

Per: ______________________________
Patrick J. Hurley, B. Math, CMA

ORILLIA POWER GENERATION CORPORATION

Per: ______________________________
John F. Mattinson, P. Eng.

SCHEDULE "A"

ARBITRATION

Any dispute between the parties hereto, or any matter to be submitted to arbitration hereunder, whether arising during the period of this Agreement or at any time thereafter which touches upon the validity, construction, meaning, performance or effect of this Agreement or the rights and liabilities of the parties hereto or any matter arising out of or connected with this Agreement shall be subject to arbitration pursuant to the Arbitrations Act (Ontario) and as provided in this Schedule A and the decision shall be final and binding as between the parties hereto and shall not be subject to appeal.

Any arbitration to be carried out under this Schedule A shall be subject to the following provisions, namely:

The party desiring arbitration shall nominate one (1) arbitrator and shall notify the other party hereto of such nomination. Such notice shall set forth a brief description of the matter submitted for arbitration and, if appropriate, the paragraph hereto pursuant to which such matter is so submitted. Such other party shall within thirty (30) days after receiving such notice nominate an arbitrator and the two (2) arbitrators shall select a chairman of the arbitral tribunal to act jointly with them. If the said arbitrators shall be unable to agree in the selection of such chairman, the chairman shall be designated by a Judge of the Ontario Court (General Division) or any successor hereto upon an application. The arbitration shall take place in the City of Orillia and the chairman shall fix the time and place in the City of Orillia for the purpose of hearing such evidence and representations as either of the parties may present and subject to provisions hereto, the decision of the arbitrators and chairman or of any two (2) of them in writing shall be binding upon the parties both in respect of procedure and the conduct of the parties during the proceedings and the final determination of the issues herein. Said arbitrators and chairman shall, after hearing evidence and representations that the parties may submit, make their decision and reduce the same to writing and deliver one (1) copy thereof to each of the parties hereto. The majority of the chairman and arbitrators may determine any matters of procedure for the arbitration not specified herein.

If the party hereto receiving the notice of the nomination of an arbitrator by the party desiring arbitration fails within the thirty (30) days to nominate an arbitrator, then the arbitrator nominated by the party desiring arbitration may proceed alone to determine the dispute in such manner and at such time as he shall think fit and his decision shall, subject to the provisions hereof, be binding upon the parties.

Notwithstanding the foregoing, any arbitration may be carried out by a single arbitrator if the parties agree here so agree, in which event the provisions of this paragraph shall apply, mutatis mutandis.

Ontario Energy Board
P.O. Box 2319
26th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie de l'Ontario
C.P. 2319
26e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY PRIORITY POST

October 22, 2002

Mr. John Mattinson
General Manager & Secretary
Orillia Power Distribution Corporation
Box 398
360 West St. S.
Orillia, ON
L3V 6J9

RECEIVED
OCT 24 2002
ORILLIA POWER CORPORATION

Dear Mr. Mattinson:

Re: Application for Exemption from the Affiliate Relationship Code for Electricity Distributors and Transmitters
<u>Board File No. RP-2002-0071/EB-2002-0365</u>

The Board has today issued its Decision and Order in the above matter and an executed copy is enclosed herewith.

Yours truly,

Peter H. O'Dell
Assistant Board Secretary

cc: P. Hurley

Encl.

RP-2002-0071
EB-2002-0365

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B;

AND IN THE MATTER OF an application by Orillia Power Distribution Corporation for exemptions from sections 2.1.2, 2.2.2, 2.2.3, 2.2.4, 2.3.1, 2.3.2 of the Affiliate Relationships Code for Electricity Distributors and Transmitters and exemption from section 2.2.2 of the Standard Supply Service Code for Electricity Distributors;

BEFORE: Paul Sommerville
Presiding Member

Bob Betts
Member

DECISION AND ORDER

October 22, 2002

1 THE APPLICATION AND BACKGROUND

1.1 On May 31, 2002 Orillia Power Distribution Corporation("Orillia Power Distribution" or the "Applicant") filed an application (the "Application") with the Ontario Energy Board (the "Board") for exemptions from sections 2.1.2, 2.2.2, 2.2.4, 2.3.1 and 2.3.2 of the Affiliate Relationships Code for Electricity Distributors and Transmitters (the "ARC"). By correspondence of August 13, 2002, Orillia Power Distribution amended its original application by applying for an additional exemption from section 2.2.3 of the ARC. On October 15, 2002, the Applicant filed an application with the Board for an exemption from section 2.2.2 of the Standard Supply Service Code for Electricity Distributors (the "SSS" Code).

1.2 Orillia Power Distribution and Orillia Power Generation Corporation (the "Companies") intend to enter into a Services Agreement in accordance with section 2.2.1 of the ARC to provide services to each other.

1.3 Orillia Power Distribution proposes to provide the following services to Orillia Power Generation Corporation ("Orillia Power Generation"): office rent and building maintenance, purchasing, stores management, safety monitoring, environmental compliance monitoring, human resources administration, bookkeeping, payroll, fleet management, financial management, tax administration, information technology, engineering services, and monitoring status of generating facilities using SCADA (Supervisory Control And Data Acquisition) technology.

1.4 Orillia Power Distribution proposes that Orillia Power Generation provide the following services to Orillia Power Distribution: generating and supplying electricity, maintenance of substations, staff supervision and technical support of monitoring facilities, and coordination of building maintenance and security.

2. SPECIFIC EXEMPTION APPLICATIONS

Physical Separation

2.1 Section 2.1.2 of the ARC provides:

A utility shall be physically separated from any affiliate who is an energy service provider.

2.2 In its letter dated May 29, 2002, Orillia Power Distribution states that Orillia Power Corporation, the holding company of Orillia Power Distribution and Orillia Power Generation, presently has a single control centre with an operator and a SCADA system to monitor and control the distribution system and generation assets of the Companies. A requirement for physical separation of the Companies would greatly increase cost and inefficiency from historical levels, thus, negatively affecting the Companies. As the Companies are not in the electricity retail business, there is no competitive advantage gained by the absence of physical separation.

Access to Confidential Information

2.3 Sections 2.2.2, 2.2.3 and 2.2.4 of the ARC provide:

> 2.2.2 Where a utility shares information services with an affiliate, all confidential information must be protected from access by the affiliate. Access to a utility's information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols and the Services Agreement shall be ensured as necessary, through a review which complies with the provisions of section 5900 of the CICA Handbook. The Board may provide direction regarding the terms of the section 5900 review. The results of any review shall be made available to the Board.
>
> 2.2.3 A utility may share employees with an affiliate provided that the employees to be shared are not directly involved in collecting, or have access to, confidential information.
>
> 2.2.4 A utility shall not share with an affiliate that is an energy service provider employees that carry out the day-to-day operation of the utility' s transmission or distribution network.

2.4 Orillia Power Distribution requested exemptions from sections 2.2.2, 2.2.3, 2.2.4 of the ARC to allow the Companies to share confidential information and to share employees that are involved in the operation of Orillia Power

Distribution's distribution network for the purpose of providing services to each other in accordance with their Services Agreement.

2.5 Orillia Power Distribution submitted that precluding the use of generation personnel to work on distribution substations will negatively affect costs and flexibility of the Companies. The shared confidential information and employees are used to efficiently operate the generation facilities and meet Orillia Power Distribution's obligations required by its distribution licence. The non-disclosure of confidential information to other persons is addressed in the Services Agreement.

Cost of Services

2.6 Section 2.3.1, 2.3.2 and 2.3.3 of the ARC provide:

> 2.3.1 Where a utility provides a service, resource or product to an affiliate, the utility shall ensure that the sale price is no less than the fair market value of the service, resource or product.
>
> 2.3.2 In purchasing a service, resource or product, from an affiliate, a utility shall pay no more than the fair market value. For the purpose of purchasing a service, resource or product a valid tendering process shall be evidence of fair market value.
>
> 2.3.3 Where a fair market value is not available for any product, resource or service, a utility shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital. The return component shall be the higher of the utility' s approved rate of return or the bank prime rate.

2.7 Orillia Power Distribution has requested exemptions from sections 2.3.1 and 2.3.2 of the ARC to allow the Companies to provide service to each other at cost-based price without cross subsidization. Pursuant to the Services Agreement, the cost-based price reflects the costs of producing the service, including a reasonable rate of return on invested capital which is defined as the higher of Orillia Power Distribution's rate of return approved by the Board or the bank prime rate.

2.8 On August 13, 2002, by way of a modified Services Agreement, Orillia Power Distribution submitted that the actual costs for each type of service shall be tracked within the Companies' workorder system. Specific costs will be allocated to each company based on supporting documents. Electricity generated and supplied to Orillia Power Distribution by Orillia Power Generation will be the Hourly Ontario Energy Price ("HOEP") as determined by the spot market .

2.9 On June 19, 2002 and July 2, 2002, Orillia Power Distribution further clarified that the generation capacity of Orillia Power Generation is not pivotal in IMO Administered Market during peak demand and Orillia Power Generation will not demand a price above competitive levels. Orillia Power Generation has no other bilateral agreements except for agreements regarding transactions for Standard Supply Service ("SSS") with Orillia Power Distribution and Hydro One Networks in which it is embedded. As a market price taker, Orillia Power Generation does not demand a price higher than HOEP.

3. BOARD FINDINGS

3.1 The Board has proceeded with the Application without a hearing as no one other than the applicant is materially adversely affected by the application. While the Board has considered all of the evidence filed in this proceeding, the Board has only referenced the evidence to the extent necessary to provide background to its findings.

3.2 The Board finds approving the exemptions from sections 2.1.2, 2.2.2, 2.2.3 and 2.2.4 is in the public interest as it will allow the continued realization of economic efficiency of the Companies and continued savings to ratepayers.

3.3 The Board is satisfied that Orillia Power Generation, a market price taker, does not demand a price above competitive levels and so Orillia Power Distribution is in compliance with section 2.3.2 of the ARC for the purchase of power from Orillia Power Generation. The Services Agreement is to be signed by the Companies to prevent Orillia Power Distribution from cross-subsidizing Orillia Power Generation or providing it with favored treatment.

3.4 The Board notes that the Applicant's proposal regarding cost of services including a reasonable rate of return meets the requirement of section 2.3.3 of the Code. Therefore, granting the exemptions from sections 2.3.1 and 2.3.2 is not necessary at this time.

3.5 The Board finds that granting the exemption from section 2.2.2 of the SSS Code and allowing Orillia Power Distribution to purchase the electricity from

Orillia Power Generation to fulfill its obligation to sell electricity to consumers under standard supply service is in public interest.

4. THE BOARD HEREBY ORDERS THAT:

Orillia Power Distribution Corporation is exempted from sections 2.1.2, 2.2.2, 2.2.3, 2.2.4 of the ARC and section 2.2.2 of the SSS Code. The exemptions are provided under the following conditions:

1. The exemptions only apply with respect to Orillia Power Distribution Corporation's relationship with Orillia Power Generation Corporation and not with respect to any other affiliate of Orillia Power Distribution Corporation.
2. The shared facilities, employees and confidential information shall only be used for the purpose of services provided by the Companies to each other pursuant to the Services Agreement.

3. The activities of the Companies are bound by the Services Agreement which is subject to the Board's review and investigation. No amendment shall be made to the Services Agreement without the prior approval of the Board. The Applicant shall report to the Board before any services are provided under clause 1.01(o) or clause 1.02(e) of the Services Agreement.

4. The Applicant shall report to the Board any material changes with respect to the materials filed in support of the Application and the above conditions within fifteen days of the date upon which such change occurs. At that time, the Board may review these exemptions to ensure that any potential harm to ratepayers and competitors of Orillia Power Generation caused by any

unfair competitive advantages or preferential treatment which Orillia Power Generation may obtain from Orillia Power Distribution as a result of the exemptions is minimized. The Board may upon reviewing the report of the Applicant, revoke some or all of the exemptions granted by this order or vary the conditions set out in this order.

DATED at Toronto October 22, 2002.

Paul Sommerville
Presiding Member

Bob Betts
Member

School Energy Coalition (SEC) INTERROGATORY #10

Interrogatory:

[Ex. A/3/1, p. 2] Please explain the rationale behind sharing the predetermined ESM amounts at the time of rebasing, as opposed to sharing them as they are accruing during years 6-10. Without limiting the generality of the question, please include an estimate of the "future rate mitigation that might be required", including all supporting calculations.

Response:

Please refer to Exhibit I, Tab 4, Schedule 15.

Hydro One has not calculated an estimate of any future rate mitigation that might be required as future rates will be determined as part of separate rate application.

School Energy Coalition (SEC) INTERROGATORY #11

Interrogatory:

[Ex. A/3/1, p. 3] Please confirm that Hydro One is not proposing to share earnings with OPDC ratepayers, but instead is proposing to replace the 1% rate benefit for years 1-5 with a predetermined ratepayer benefit of $3.4 million to be paid in years 11 and beyond.

Response:

No, Hydro One does not confirm this assumption.

School Energy Coalition (SEC) INTERROGATORY #12

Interrogatory:

[Ex. A/3/1, p. 5] Please recalculate the $3.4 million ESM amount using Hydro One's current weighted average cost of debt for 2017, and Hydro One's current approved ROE for 2017. Please explain why, if one of the cost benefits claimed by Hydro One in this Application is a lower cost of capital, Hydro One thought it was appropriate not to based its ESM on sharing that cost saving as well.

Response:

Please see Exhibit I, Tab 1, Schedule 21.

Using Hydro One's weighted average cost of debt for 2017 (4.43%) and its current approved ROE (8.78%) the customer refund amount would be $5.1M. However, as noted in the reference above, those assumed values are not a consideration in the proposed ESM.

The Consolidation Handbook indicates that rate resetting during the deferred rebasing period is based upon the principles under the OEB's RRFE. Each of the rate-setting mechanisms available provides that an annual adjustment mechanism be applied to current approved rates. Those rates have been determined on approved capital parameters with annual adjustments made via inflation and productivity factors, changes are not made to the utility's approved ROE or its debt rates.

The OEB's polices and recent decisions on MAAD applications emphasize the need to ensure that long term benefits are achievable while recognizing that the shareholder can benefit from the savings resulting from the application:

> "*Distributors are provided with the opportunity over a 5-10 year period to offset initial transaction costs and subsequently benefit from the cost savings that successful consolidations can generate*[1]."

Hydro One contends that the debt and equity rates used are the appropriate rates to use in the ESM calculation.

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[1] EB-2015-0003, Page 6

After the 10 year rebasing deferral period elapses and OPDC is rebased, OPDC's customers will enjoy 100% of the savings due to synergies that result from the lower cost structures than would have otherwise been the case (i.e., in the absence of the transaction).

School Energy Coalition (SEC) INTERROGATORY #13

Interrogatory:

[Ex. A/3/1, p. 7] The following table expands Table 6 to include the first five years, and makes three other changes: a) Target ROE is at the current Board-approved 8.78%, b) cost of debt is at the Hydro One rate of 4.86%, and c) the OM&A figure is the actual forecast of OM&A from Table 1.

a) Please confirm that, with those changes, this is materially similar to Hydro One's own forecast for the ten year deferred rebasing period.

b) Please confirm that it is reasonable to assume that Hydro One will receive $42 million in pre-tax profits over that period, and the ratepayers $3.4 million.

c) Please confirm that, if Hydro One is not required to pay income tax on its share of profits, it can reasonably expect to net more than $28 million in excess of the Board's ROE.

d) Please confirm further that neither Table 6, nor this expanded table, assume customer growth in the OPDC service territory during that ten year period.

Extended forecast of Earnings Years 1 - 10 (Expanded Table 6)

Item	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Totals
Rate Base	32,973	34,308	35,700	37,149	38,659	40,231	41,869	43,576	45,371	47,242	39,708
Equity Component of Rate Base	13,189	13,723	14,280	14,860	15,463	16,092	16,748	17,430	18,148	18,897	15,883
Revenue	8,600	8,600	8,600	8,600	8,600	8,600	8,792	8,996	9,199	9,410	87,997
OM&A	4,100	2,100	2,000	1,700	1,700	1,700	1,800	1,800	1,900	1,900	20,700
Depreciation	798	841	885	932	982	1,036	1,091	1,147	1,211	1,278	10,201
Interest at Hydro One rates (4.86%)	961	1,000	1,041	1,083	1,127	1,173	1,221	1,271	1,323	1,378	11,579
Net profit before tax	2,741	4,659	4,674	4,884	4,791	4,691	4,680	4,778	4,765	4,854	45,517
Tax provision	726	1,235	1,239	1,294	1,270	1,243	1,240	1,266	1,263	1,286	12,062
Net Profit after tax	2,014	3,424	3,435	3,590	3,521	3,448	3,440	3,512	3,502	3,568	33,455
Achieved ROE	15.27%	24.95%	24.06%	24.16%	22.77%	21.42%	20.54%	20.15%	19.30%	18.88%	21.06%
Target ROE @ 8.78%	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%

Excess ROE	6.49%	16.17%	15.28%	15.38%	13.99%	12.64%	11.76%	11.37%	10.52%	10.10%	12.28%
After-tax Overearnings	856	2,219	2,181	2,285	2,164	2,035	1,969	1,982	1,909	1,909	19,510
Grossed-up to Pre-Tax Overearnings	1,165	3,020	2,968	3,109	2,944	2,769	2,680	2,696	2,597	2,597	26,544
Net Proposed Share to Customers	0	0	0	0	0	767	721	676	622	566	3,352
Net Share to Hydro One	856	2,219	2,181	2,285	2,164	1,268	1,248	1,306	1,287	1,343	16,158
Add back tax provision	1,583	3,454	3,420	3,580	3,433	2,511	2,489	2,572	2,550	2,629	28,220

Response:

a) Hydro One cannot confirm the calculations proposed in the Expanded Table 6 provided by SEC. Hydro One is requesting approval of the ESM as filed in this Application. Changes to the proposed ESM, including the alternative assumptions put forward in the above table, have not been contemplated.

Please refer to Exhibit I, Tab 1, Schedule 21.

b) As stated in part a) above Hydro One has not confirmed the pre-tax profits scenario presented in this question. The Consolidation Policy allows for shareholders to retain any excess earnings in the first five years to offset transaction and integration costs; the following five years, those excess earnings are shared on a 50/50 basis with customers for earnings in excess of 300 basis points above a distributor's approved ROE.

In addition to limiting base distribution rate increases to a rate lower than inflation, Hydro One's proposed ESM benefits customers by providing a guaranteed refund on forecast earnings in years 6 to 10. Additionally, the ESM shields customers from variations in load and customer growth forecast, interest rate increases and any other changes in economic conditions and operating costs over years 6 to 10. Prior to the commencement of the ESM customers will also benefit from a 1% base distribution rate reduction in years 1 to 5 (held constant). Together these provide overall rate certainty for a ten year period. Hydro One believes these, together with a material, guaranteed reduction in OM&A are substantial benefits to customers in which Hydro One's shareholder is taking all the risks of achievement.

c) Not confirmed. Please see Exhibit I, Tab 5, Schedule 3. Hydro One does not find it reasonable to assume that it is not required to pay taxes on the earnings of the OPDC business segment over the 10 year rate rebasing deferral period. Hydro One, through the purchase price paid to the current owner to acquire the shares of OPDC incurred the cost for OPDC's departure tax payment, which represents part of the premium paid on the acquisition. Hydro One's assumption is that the premium would be recovered, in part, over time by the benefit of tax deductions arising from the fair market bump. This assumption is consistent with the OEB's MAADs policy.

Ratepayers will remain unaffected by the departure tax payment and the deferred tax asset benefits. None of these relate to the provision of rate regulated distribution services. Hydro One's position is consistent with the argument, referred to Exhibit I, Tab 3, Schedule 3d), that cost causation (benefits follow costs) and stand-alone principles should be applied in the same manner.

Regarding the extent of potential returns flowing to the consolidating shareholder over the deferral period, Hydro One disputes any inference by SEC that the benefits flowing to ratepayers and shareholders from the ESM as a result of this proposed consolidation are in some way not adhering to the Board's direction or policy. Hydro One maintains that it has provided an ESM that is consistent with the OEB's intent as outlined in the Handbook, and recent MAAD decisions, that benefits flow to the shareholder over the deferral period. The Board's intent of consolidation, as reemphasized in the recent LDC Co. Decision on Threshold Question[1],

> "*is to realize long term savings that endure beyond the 5-10 year period through shorter term financial incentives.*"

d) Not Confirmed. Table 6 included in the prefiled evidence does include Hydro One's forecast of OPDC customer and load growth. Please refer to Exhibit I, Tab 3, Schedule 18 part b.

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[1] EB-2015-0003, Decision on Threshold Question and Procedural Order No. 5, Page 6

School Energy Coalition (SEC) INTERROGATORY #14

Interrogatory:

[Ex. A/3/1, p. 8] Please explain why the ESM deferral account should bear interest at prescribed interest rates, rather than Hydro One's weighted average cost of capital.

Response:

Hydro One submits that the ESM deferral account should be treated similar to any other deferral and variance account and should bear interest at the OEB prescribed interest rates.

School Energy Coalition (SEC) INTERROGATORY #15

Interrogatory:

[Attachment 5, p. 15] Please confirm that there is no adjustment to the purchase price, nor any payment by the Purchaser or the Vendor under section 2.6(b) or any other section, if the Board orders a negative rate rider in excess of 1%, or for a longer period than 5 years.

Response:

Section 2.6(b) of the Share Purchase Agreement addresses payments the Purchaser will make to the Vendor in the event of a Partial Rate Rider[1], i.e., if the OEB approved a negative rate rider that results in an average reduction in Current Rates of less than the 1% across all Rate Classes contemplated by this transaction.

As was determined in the Combined Proceeding Decision[2], confirmed in recent MAAD decisions that SEC has participated in, and outlined in the OEB Handbook to Electricity Distributor and Transmitter Consolidations[3], the application of the "no harm" test is limited to the effect of the proposed transaction before the OEB when considered in light of the OEB's statutory objectives. The OEB determined in the Combined Proceeding Decision that it is not the OEB's role to determine whether another transaction, whether real or potential, can have a more positive effect than the transaction that has been placed before the OEB.

No assessment to the purchase price was ever completed for a negative rate rider, either in excess of 1% for five years, or, for a period longer than five years, since these items are not contemplated by the transaction that has been placed before the OEB. As a result, no section of the SPA would address these potential changes to the transaction.

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[1] Share Purchase Agreement - Defined Term (aaaa) – Page 7
[2] Combined Proceeding Decision - RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257
[3] OEB Handbook to Electricity Distributor and Transmitter Consolidations – Page 9 – January 19, 2016

School Energy Coalition (SEC) INTERROGATORY #16

Interrogatory:

[Attachment 5, p. 19] Please provide the table of contents or other listing of the contents of the Confidential Disclosure Schedule, without including in response the actual details of any confidential information included therein.

Response:

The Confidential Disclosure Schedule contains:

- exceptions to the representations made in subsections 3.1(l), and(t) of the Share Purchase Agreement
- the Employee Fact Sheet
- contracts with employees, officers and directors
- litigation involving the utility
- the utility's bank accounts.

School Energy Coalition (SEC) INTERROGATORY #17

Interrogatory:

[Attachment 5, p. 34] Please provide details of all entries in account 1576 for 2016, and all expected or forecast entries in that account in 2017.

Response:

Please see Attachment 1, which was prepared using a preliminary estimate for 2016 unbilled and estimates for 2016 and 2017 difference in amortization expense based on 2015 actual.

If Hydro One's Application is approved by the OEB, no new entries will be entered in Account 1576, Change in PP&E Useful Life Estimates in 2017 as the transition to IFRS will no longer be applicable to OPDC.

Exhibit I, Tab 5, Schedule 17 - Attachment 1

Orillia Power Distribution Inc.

Deferral and Variance Account: 1576 - Change in PP&E useful lives estimates	Note	$'s
Account Balance as at December 31, 2015	1	**(1,936,348)**
Refunds to customers:		
2016 Rate Rider Refund to Customers	2	1,484,925
Additions to account:		
Rate of return included in the Rate rider balance refunded	3	(96,476)
2016 difference in amortization expense - due to change in estimated useful lives (estimate)	4	(650,000)
Account Balance as at December 31, 2016 (forecast)		**(1,197,899)**
Additions to account:		
2017 difference in amortization expense - due to change in estimated useful lives (estimate)	4	(650,000)
Balance December 31, 2017 (forecast)		**(1,847,899)**

Note 1 - As per OPDC's audited Financial Statements as at December 31, 2015 (Filed as Attachment 12 to the Application)
This Group 2 deferral account balance will be included in OPDC's next rebasing application for disposition and it will be subject to a true up based on actuals at that time

Note 2 - The refund to customers occurred via a Board approved rate rider [EB-2015-0286]. The rate rider was for a period of 12 months

Note 3 - These amounts relate to the Rate of Return on the Rate Rider Principal balances approved in EB-2015-0286
As per the OEB's Accounting Procedures Handbook FAQ's, issued in March 2015, the rate of return applicable is to be sourced from a Distributor's last approved rebasing.
OPDC's last rate rebasing approval was EB-2009-0273, and the applicable WAAC rate was 7.49%

Note 4 - Amounts are estimates. Actuals are not available at this time

School Energy Coalition (SEC) INTERROGATORY #18

Interrogatory:

[Attachment 5, Schedule 3.1(v) - Taxes] Please provide documents 6 and 17.

Response:

Attachment 1 is the 2015 Tax Return referred to in the question as document 6.

Attachment 2 is the Notice of Assessment referred to in the question as document 17.

June 28, 2016

PERSONAL AND CONFIDENTIAL

Pat Hurley
Officer
Orillia Power Distribution Corporation
360 West St S
P.O. Box 398
Orillia ON L3V 6J9

Dear Mr. Hurley,

Corporate Tax Return Filing Instructions

T2 - CORPORATION INCOME TAX RETURN (FEDERAL)

The "T2 Bar codes format" has been adopted by the Canada Revenue Agency (CRA) for corporate income tax returns produced by tax preparation software. The traditional federal forms no longer have to be filed. Furthermore, the CRA requires that the General Index of Financial Information (GIFI) be used to report financial statement information.

The form containing the T2 bar codes includes information from your corporation's income tax return and all applicable schedules (traditional federal forms), including the GIFI.

Signature

- The form containing the T2 bar codes should be completed and signed.

- Form RC59, *Business Consent*, should be completed and signed.

Payment

- You must make a payment of $**216,173** to the *Receiver General* as soon as possible to minimize interest charges. You can make the payment using CRA's *My Payment* online service, at a financial institution or by cheque.

  If you are paying by cheque, make the cheque payable to *the Receiver General of Canada* and indicate the corporation's Business number as well as the end date of the taxation period, i.e. December 31, 2015.

Mailing

- A copy of the form containing the T2 bar codes (and of any required federal form, such as Form RC59 and Form RC321) should be sent to the CRA no later than June 30, 2016.

Federal tax instalments (monthly)

Due date	Amount
2016-01-31	$27,659
2016-02-29	$27,659
2016-03-31	$27,659
2016-04-30	$27,659
2016-05-31	$27,659
2016-06-30	$27,659
2016-07-31	$27,659
2016-08-31	$27,659
2016-09-30	$27,659
2016-10-31	$27,659
2016-11-30	$27,659
2016-12-31	$27,657
Total	$331,906

If you have any questions about your return(s), please contact us at (705) 726-6331.

Sincerely yours,

BDO Canada LLP

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2016-12-31

Business number 86512 0596 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Canada Revenue Agency. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. Payment may be made by cheque or money order payable to the Receiver General either at an authorized financial institution or filed with **the appropriate remittance voucher at the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2016-01-31	27,659				27,659
2016-02-29	27,659				27,659
2016-03-31	27,659				27,659
2016-04-30	27,659				27,659
2016-05-31	27,659				27,659
2016-06-30	27,659				27,659
2016-07-31	27,659				27,659
2016-08-31	27,659				27,659
2016-09-30	27,659				27,659
2016-10-31	27,659				27,659
2016-11-30	27,659				27,659
2016-12-31	27,657				27,657
Totals	331,906				331,906

Ontario Ministry of Finance

Authorizing or Cancelling a Representative

Version française disponible.

Please read the Important Information on page 2.

Complete this form when you have dealings with the Ontario Ministry of Finance and you need to:

- **authorize** the ministry to deal with another individual (such as your spouse, other family member, accountant, tax consultant, or solicitor) as your representative for Ontario tax/program matters as selected by you in **Part 1** below.
- **cancel** one or more existing **authorizations**.

Part 1 Client Information

Legal name (Corporate name, if applicable)
Last: Orillia Power Generation
First: Corporation

Daytime phone number: (705) 326-7315

Business Number: 8 6 5 1 2 2 9 9 8

Mailing address
Apt./Suite/Unit No.: 360
Street number and name: West St. S
PO Box, R.R., Postal Stn: 398
City: Orillia
Province/Territory/State: ON
Postal/Zip code: L 3 V 6 J 9

Please specify under which statute(s)/program(s) your representative will be acting on your behalf and state your appropriate account, permit or reference number(s).

- [x] *Electricity Act, 1998*
  - [ ] *Debt Retirement Charge*
  - [ ] *Gross Revenue Charge*
  - [x] *Payments In lieu of Federal and Provincial Corporate Tax*: 8 6 5 1 2 2 9 9 8 R C 0 0 0 1
- [ ] *Employer Health Tax Act*
- [ ] *Alcohol and Gaming Regulation and Public Protection Act,1996*
  - [ ] *Beer Account*
  - [ ] *Wine Account*
- [ ] *Land Transfer Tax Act*
- [ ] *International Fuel Tax Agreement*
- [ ] *Retail Sales Tax Act*
- [ ] *Gasoline Tax Act*
- [ ] *Fuel Tax Act*
- [ ] *Tobacco Tax Act*
  - [ ] *Tobacco Account*
  - [ ] *Tobacco Retail Dealer's Account*
- [ ] *Mining Tax Act*
- [ ] *Corporation Tax Act*
  - [ ] *CT - Insurance Premium Tax*
  - [ ] *CT - Corporation Tax* (for taxation periods prior to 2008-12-31)
- [ ] *Estate Administration Tax Act, 1998*
- [ ] *Race Tracks Tax Act*

Part 2 Authorizing a Representative

Name of representative
Last:
First:

Title (if applicable):

Name of firm (if applicable): BDO Canada LLP

Mailing Address
Apt./Suite/Unit No.: 19
Street number and name: Front St N
PO Box, R.R., Postal Stn: 670
City: Orillia
Province/Territory/State: Ontario
Postal/Zip code: L 3 V 6 K 5

Daytime phone number: (705) 325-1386

Fax number: (705) 325-6649

Scope of Authorization

Authorize your representative to act on your behalf with the Ministry of Finance for the purposes of Ontario tax/program matters, under the account or reference number(s), specified in **Part 1**. You can authorize your representative to receive certain mail addressed to the address provided in **Part 2** of this form, on your behalf, by checking the Mail Returns, Mail Credentials and Mail Statement/Assessment listed below.

- [x] **in all matters;** **or** [ ] **only for matters specified below.**

Check all that apply

- [ ] Applications
- [ ] Assessments
- [ ] Objections
- [ ] Appeals
- [ ] Renewals
- [ ] Returns
- [ ] Rulings/ Interpretations
- [ ] Statements
- [ ] Mail Returns
- [ ] Mail Credentials
- [ ] Mail Statements/ Assessments
- [ ] File electronic rebates/refunds
- [ ] File manual rebates/refunds
- [ ] Other Specify
- [ ] File and receive electronic rebates/refunds
- [ ] File and receive manual rebates/refunds
- [ ] Transmission of confidential information by facsimile

Year(s) to which this authorization applies

- [x] **All** years, including all previous and future years

or

- [ ] **Specific** year or years (no more than 6 years) Specify

Continued on page 2

Part 3 **Cancelling one or more existing authorizations** (Choose **one** of the following.)

☐ Cancel **all** existing authorizations.

or

☐ Cancel **all** existing authorizations **given to the representative** shown below.

Name of representative Last	First	Title (if applicable)
Name of firm (if applicable)		

Part 4 **Signature** ***This form will not be accepted unless it is signed.***

By signing this form, you authorize the Ministry of Finance to:

- deal with the representative identified in **Part 2** according to the details provided;
- cancel the existing authorization(s) described in **Part 3**.

It is your responsibility to monitor and understand the transactions your representative is conducting on your behalf and to make sure that the information regarding your representative is current. If you feel your representative is not acting in your best interests, you should immediately cancel authorization of your representative.

Individual or authorized person Name (print) Last	First	Signature	Date
Hurley	Pat		
Title: Officer			

The personal information provided by you on this form is collected under the authority of the Acts shown on page 1 of this form, and will be used for the purpose of determining the authority of a representative who requests information or activity on your account. Questions about this collection may be directed to an Agent of the Ministry at 1 866 ONT-TAXS (1 866 668-8297) or in writing to the address provided in the instructions.

Important Information

Why do you need to complete this form?

Tax information is confidential. If you want the Ministry of Finance (ministry) to deal with another individual (such as your spouse, accountant or solicitor) as your representative, we need your authorization. You can do this by completing **Parts 1**, **2**, and **4** of this form.

Your authorization will stay in effect until you cancel it. You can cancel an existing authorization by completing **Parts 1**, **3**, and **4** of this form. All authorizations are automatically cancelled upon notification of the representative's death.

You will have to complete a new *Authorizing or Cancelling a Representative* form if you want to change any information about an existing representative. For example, if your representative is a firm, you may authorize the ministry to deal with a specific individual in that firm. In a future year, should you want to replace that individual with another individual in the same firm, you will have to complete a new form to update your authorization.

You can have more than one authorized representative at the same time. However, you have to complete a separate *Authorizing or Cancelling a Representative* form for each representative.

Does your spouse, common-law partner, or other family member need your authorization?

Yes. The ministry cannot deal with your spouse, common-law partner, son, daughter, other family member or friend without your signed authorization.

What will your representative be allowed to do?

When you authorize the ministry to deal with a representative or to receive certain pieces of mail, you are allowing that person to act on your behalf for matters under the tax acts as selected by you in **Part 1**, for the tax year or years you specified in **Part 2.** For example, the representative will be allowed to resolve and/or discuss your confidential tax information with the ministry and ask the ministry to make changes to your tax Return. Should you wish to authorize your representative to represent you in specific issues or receive certain pieces of mail on your behalf, please specify which issues they are authorized to act on your behalf and/or what types of mail they can receive, in **Part 2.**

What happens if you do not sign this form?

If you do not sign this form, the ministry cannot be sure that you have given the authority to deal with the representative identified on the form. To protect the confidentiality of your tax information, the ministry will not accept or act on any information given on this form unless you have signed the form.

If you need more information or further assistance in completing this form –

call:

Ministry of Finance 1 866 ONT-TAXS (1 866 668-8297)
Teletypewriter (TTY) 1 800 263-7776
or visit our website at: **ontario.ca/finance**

Mail your completed form to:

Ministry of Finance
33 King Street West
PO Box 627
Oshawa ON L1H 8H5

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 **Do not use this area**

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 86512 0596 RC0001

Corporation's name
002 Orillia Power Distribution Corporation

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.)
011 360 West St S
012 P.O. Box 398
City: 015 Orillia
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 L3V 6J9

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 360 West St S
022 P.O. Box 398
023 Orillia
City: 025
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal code/Zip code: 028 L3V 6J9

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.)
031 360 West St S
032 P.O. Box 398
City: 035 Orillia
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 L3V 6J9

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 2015-01-01 (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.

		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		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	X	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	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	X	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 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?	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	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 products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity 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 (YYYY MM DD)	294		
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295		

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		1,539,688	A
Deduct: Charitable donations from Schedule 2	311	259,249		
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		259,249 ►	259,249	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			1,280,439	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		1,280,439	
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)			1,280,439	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	1,531,603 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	1,280,439 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 *** 99,275 / 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 (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) 365 / 365 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) ______ / 365 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)			1,280,439	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*	8,085	G		
Subtotal (**add** amounts B to G)	8,085	►	8,085	H
Amount A **minus** amount H (if negative, enter "0")			1,272,354	I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 %			165,406	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** 8,085 x (26 2 / 3 + 4 x (Number of days in the tax year after 2015) / (365 Number of days in the tax year)) % = 2,156 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) / (365 Number of days in the tax year)) % = ______ C

(if negative, enter "0") ______ ▶ ______ D

Amount A **minus** amount D (if negative, enter "0") . . . . 2,156 E

Taxable income from line 360 on page 3 . . . . 1,280,439 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

1,280,439 K

K x (26 2 / 3 + 4 x (Number of days in the tax year after 2015) / (Number of days in the tax year 365)) % = 341,450 L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . 193,656 M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** 2,156 N

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year **460** 8,176

Deduct: Dividend refund for the previous tax year . . . . **465** ______

8,176 ▶ 8,176 O

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . 2,156 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** ______

2,156 ▶ 2,156 R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R **485** 10,332

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 . . . . 1,230,000 x [(1 / 3) + (5 x (Number of days in the tax year after 2015) / (365 Number of days in the tax year)) %] = 410,000 S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . 10,332 T

Dividend refund – Amount S or T, whichever is less . . . . 10,332 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	486,567	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 365) 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		8,085	C
Taxable income from line 360 on page 3	1,280,439 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)	1,280,439 ▶	1,280,439	F

Refundable tax on CCPC's investment income –

(6 2 / 3 + 4 x (Number of days in the tax year after 2015 ____ / 365 Number of days in the tax year)) % of whichever is less: amount C or amount F

Refundable tax on CCPC's investment income	604	539	G
Subtotal (**add** amounts A, B, and G)		487,106	H

Deduct:

Small business deduction from line 430 on page 4			I
Federal tax abatement	608	128,044	
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	165,406	
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		293,450 ▶ 293,450	J

Part I tax payable – Amount H **minus** amount J	193,656	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	193,656
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		193,656

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	138,250	
Total tax payable	770	331,906	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount U on page 6	784	10,332
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	105,401
Total credits	890	115,733 ► 115,733 B

Refund code 894 [ ] Overpayment ______ Balance (amount A **minus** amount B) 216,173

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 216,173

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 [X]

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920 D0258

Certification

I, 950 Hurley (Last name (print)) 951 Pat (First name (print)) 954 Officer (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 2016-06-28 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (705) 326-7315 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes [X] 2 No [ ]

958 ______ Name (print) 959 ______ 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

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
		105,401

Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	105,401	**A**
Total instalments credited to the taxation year per T9	105,401	**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
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	9,656,266	9,514,000
	Total tangible capital assets	2008	+	25,845,417	41,571,000
	Total accumulated amortization of tangible capital assets	2009	–	2,134,374	20,016,000
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	3,205,487	1,837,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	36,572,796	32,906,000
	Liabilities				
	Total current liabilities	3139	+	8,184,511	7,033,345
	Total long-term liabilities	3450	+	15,751,646	12,787,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	23,936,157	19,820,345
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	12,636,639	13,085,655
	Total liabilities and shareholder equity	3640	=	36,572,796	32,906,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	4,505,756	2,498,772

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

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
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

Income statement information

Description	GIFI	
Operating name	0001	
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	+	44,344,213	41,767,625
	Cost of sales	8518	–	36,292,097	38,447,855
	Gross profit/loss	8519	=	8,052,116	3,319,770
	Cost of sales	8518	+	36,292,097	38,447,855
	Total operating expenses	9367	+	6,710,045	1,765,145
	Total expenses (mandatory field)	9368	=	43,002,142	40,213,000
	Total revenue (mandatory field)	8299	+	44,351,463	41,754,000
	Total expenses (mandatory field)	9368	–	43,002,142	40,213,000
	Net non-farming income	9369	=	1,349,321	1,541,000

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	=	1,349,321	1,541,000
	Total other comprehensive income	9998	=		

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	–	322,000	74,000
	Future (deferred) income tax provision	9995	–	154,000	262,000
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	873,321	1,205,000

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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

	Line	1 Yes	2 No
Does the accountant have a professional designation?	095	X	
Is the accountant connected* with the corporation?	097		X

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**

	Option	
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:

	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	
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	

	Line	1 Yes	2 No
Were notes to the financial statements prepared?	101	X	
If **yes**, complete lines 104 to 107 below:			
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.

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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1. CORPORATE INFORMATION

Orillia Power Distribution Corporation (the Company) owns and operates an electricity distribution system, which delivers electricity to approximately 13,500 customers located in Orillia, Ontario. The address of the Company's corporate office and principal place of business is 360 West Street South, Orillia, Ontario, Canada L3V 6J9.

The sole shareholder of the Company is the Orillia Power Corporation.

The Company was incorporated under the Business Corporations Act (Ontario) on October 26, 2000. The Company operates under license issued by the Ontario Energy Board (OEB). The Company is regulated by the OEB and adjustments to the Company s distribution and power rates require OEB approval.

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2. BASIS OF PREPARATION

2.1 Statement of compliance

The Financial Statements of the Company have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations as issued by the International Financial Reporting Interpretations Committee (IFRIC) of the IASB.

These are the Company's first Financial Statements prepared in accordance with
IFRS and IFRS 1 First-time Adoption of
International Financial Reporting Standards has been applied. They should be
read in conjunction with the 2014 Canadian
generally accepted accounting principles (Canadian GAAP) Financial
Statements and related notes. In this context, the term
Canadian GAAP refers to generally accepted accounting principles before the
adoption of IFRS.
The Financial Statements were authorized for issue by the Board of Directors
on April 4, 2016.
2.2 First time adoption of IFRS
The transition to IFRS resulted in a decrease of shareholders equity of $195
and $93 at January 1, 2014 and December 31, 2014
respectively and an increase in Comprehensive Income for the year end December
31, 2014 of $102. In addition, the adoption of
IFRS 14, Regulatory Deferral Accounts, resulted in a significant change in
presentation, as regulatory deferral accounts are now
presented separately from assets and liabilities and the change in regulatory
deferral accounts is presented separately from net
profit. An explanation of how the transition to IFRS has affected the reported
financial position, financial performance and cash
flows of the Company is provided in the last note to these financial
statements.
2.3 Basis of measurement
The Financial Statements have been prepared on a historical cost basis.
2.4 Presentation currency
The Financial Statements are presented in Canadian dollars (CAD), which is
also the Company s functional currency, and all

values are rounded to the nearest one thousand dollars, unless when otherwise indicated.

2.5 Explanation of activities subject to rate regulation

The Ontario government enacted the Energy Competition Act, 1998, to introduce competition to the Ontario energy market. The
Ontario Energy Board (OEB) was granted a legislative mandate including broad powers relating to licensing, standards of
conduct and service quality and the regulation of rates charged by the Company and other electricity distributors in Ontario.
The Company as an electricity generator and distributor, is licensed and regulated by the OEB. The OEB exercises statutory
authority through setting or approving all rates charged by the distribution company and establishing standards of service quality
for its customers. The Company s distribution rates are set by the OEB on an annual basis for May 1 to April 30.

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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2.6 Regulatory risk

Regulatory risk is the risk that the Province and its regulator, the Ontario Energy Board, could establish a regulatory regime that
imposes conditions that restrict the electricity distribution business from

achieving an acceptable rate of return that permits
financial sustainability of its operations including the recovery of expenses
incurred for the benefit of other market participants in
the electricity industry such as transition costs and other regulatory assets.
All requests for changes in electricity distribution
charges require the approval of the OEB.
2.7 Recovery risk
Regulatory developments in Ontario s electricity industry, including current
and possible future consultations between the OEB
and interested stakeholders, may affect distribution rates and other permitted
recoveries in the future. Orillia Power Distribution
Corporation is subject to a cost of service regulatory mechanism under which
the OEB establishes the revenues required (i) to
recover the forecast operating costs, including depreciation and amortization
and income taxes, of providing the regulated
service, and (ii) to provide a fair and reasonable return on utility
investment, or rate base. As actual operating conditions may vary
from forecast, actual returns achieved can differ from approved returns.
2.8 Potential sale of the Company
The City of Orillia and the Orillia Power Corporation are currently in
negotiations with Hydro One to sell Orillia Power Distribution
Corporation. A purchase agreement has not been signed between the negotiating
parties as of the date of approval of these
financial statements by the Board of Directors.

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3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
The preparation and presentation of financial statements can be significantly

affected by the accounting policies selected by the
Company. The financial statements reflect the following significant accounting
policies, which are an integral part of
understanding the financial results and financial position presented within.
The accounting policies set out below have been applied consistently to all
periods presented in these Financial Statements and
in preparing the opening IFRS Statement of Financial Position at January 1,
2014 for the purposes of the transition to IFRS,
unless otherwise indicated.
3.1 Regulatory deferral accounts
The Company has applied early adoption of IFRS 14 Regulatory Deferral
Accounts. In accordance with IFRS 14, the Company
has continued to apply the accounting policies it applied in accordance with
the pre-changeover Canadian GAAP for the
recognition, measurement and impairment of assets and liabilities arising from
rate regulation. These are referred to as regulatory
deferral account balances.
Regulatory deferral account debit balances represent future revenues
associated with certain costs incurred in the current period
or in prior period(s), which are expected to be recovered from consumers in
future periods through the rate-setting process.
Regulatory deferral account credit balances are associated with the collection
of certain revenues earned in the current period or
in prior period(s), which are expected to be returned to consumers in future
periods through the rate-setting process.
Regulatory deferral account balances can arise from differences in amounts
collected from customers (based on regulated rates)
and the corresponding cost of non-competitive electricity service incurred by

the Company in the wholesale market administered

by the Independent Electricity System Operator (the "IESO") after May 1, 2002.

These amounts have been accumulated pursuant

to regulation underlying the Electricity Act (the "EA") and deferred in

anticipation of their future recovery (payment) from (to)

distribution customers.

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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3.1 Regulatory deferral accounts (continued)

Explanation of Recognized Amounts

Regulatory deferral account balances are recognized and measured initially and

subsequently at cost. They are assessed for

impairment on the same basis as other non-financial assets as described below.

Management continually assesses the likelihood

of recovery of regulatory assets. If recovery through future rates is no

longer considered probable, the amounts would be charged

to the results of operations in the period that the assessment is made.

3.2 Revenue

Revenue is recognized to the extent that it is probable that economic benefits

will flow to the Company and that the revenue can

be reliably measured. Revenue is comprised of recovered energy purchases,

distribution of energy, pole use rental, collection
charges, investment income and other miscellaneous revenues.

Recovered energy purchases and distribution of energy

The Company is licensed by the OEB to distribute electricity. As a licensed
distributor, the Company is responsible for billing
customers for electricity generated by third parties and the related costs of
providing electricity service, such as transmission
services and other services provided by third parties. The Company is
required, pursuant to regulation, to remit such amounts to
these third parties, irrespective of whether the Company ultimately collects
these amounts from customers. The Company has
determined that they are acting as a principal for the electricity
distribution and, therefore, have presented the electricity revenues
on a gross basis.

Revenues from recovered energy purchases and distribution of electricity is
recognized on an accrual basis, including unbilled
revenues accrued in respect of electricity delivered but not yet billed.

Recovered energy purchases and distribution of energy
revenue is comprised of customer billings based on actual monthly meter
readings.

Other

Other revenues, which include revenues from pole use rental, collection
charges, contributions in aid of construction and other
miscellaneous revenues are recognized at the time services are provided.

Deferred revenue

Where the Company has an ongoing obligation to provide services, revenues are
recognized as the service is performed and
amounts billed in advance are recognized as deferred revenue.

Certain assets may be acquired or constructed with financial assistance in the
form of contributions from customers when the
estimated revenue is less than the cost of providing service or where special
equipment is needed to supply the customers
specific requirements. Since the contributions in aid of construction will
provide customers with ongoing access to the supply of
electricity, these contributions are classified as deferred revenue and are
amortized as revenue on a straight-line basis over the
useful life of the constructed or contributed asset.

3.3 Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held at call with
financial institutions, other short-term, highly liquid
investments with original maturities of three months or less that are readily
convertible to known amounts of cash and subject to
an insignificant risk of change in value.

Orillia Power Distribution Corporation
NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2015
(in thousands of Canadian dollars unless otherwise noted)

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3.4 Financial instruments

Recognition, initial measurement and derecognition

Financial assets and liabilities are recognized when the Company becomes a
party to the contractual provisions of the financial

instrument and are measured initially at fair value adjusted for transaction costs, except for those carried at fair value through comprehensive income which are measured initially at fair value. Subsequent measurement of financial assets and financial liabilities is described below.

Financial assets are derecognized when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and substantially all the risks and rewards are transferred. A financial liability is derecognized when it is extinguished, discharged, cancelled or expires.

Classification and subsequent measurement of financial assets

For the purpose of subsequent measurement of financial assets, they are classified into the following categories upon initial recognition, loans and receivables and available-for-sale financial assets. The company currently does not have assets that would be classified as available for sale. All financial assets classified as loans and receivables are reviewed for impairment at least at each reporting date to identify whether there is any objective evidence of impairment. All income and expenses relating to financial assets that are recognized in profit or loss are presented within finance costs or finance income, except for impairment of trade receivables which is presented within operating expenses.

Financial assets classified as loans and receivables

Financial assets classified as loans and receivables include cash and cash equivalents, accounts receivable and unbilled energy and distribution revenue. Collectability of accounts receivable is reviewed on an ongoing basis. Individually significant receivables are considered for impairment when they are past due or when other objective

evidence is received that a specific counterparty
will default. Receivables that are not considered to be individually impaired
are reviewed for impairment in groups, which are
determined by reference to the industry and region of the counterparty and
other shared credit risk characteristics. The
impairment loss estimate is then based on recent historical counterparty
default rates for each identified group. Accounts
receivable which are known to be uncollectible are written off. A provision
for doubtful receivables is established when there is
objective evidence that the Company will not be able to collect all amounts
due according to the original terms of the receivables.
The amount of the provision is the difference between the asset s carrying
amount and the present value of future cash flows.
The amount of the provision is recognized in the Statement of Comprehensive
Income.
Classification and subsequent measurement of financial liabilities
All of the Company s financial liabilities are classified as other financial
liabilities, and include bank indebtedness, accounts
payables and accrued liabilities, customer deposits, promissory notes and
Infrastructure Ontario Loans. Other financial liabilities
are measured subsequently at amortized cost using the effective interest
method. All interest-related charges are reported in
profit or loss and included within finance costs or finance income.
Customer Security Deposits
Customers may be required to post security to obtain electricity or other
services, which are refundable. Cash and securities
lodged with the Company by counterparties under electricity supply agreements
are also included in this balance. Where the

security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer security deposits. Interest rates paid on customer deposits are based on the Bank of Canada s prime business rate less 2%.

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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3.5 Property, plant and equipment

Recognition and measurement

Property, plant and equipment (PP&E) are recognized at cost, being the purchase price and directly attributable cost of acquisition or construction required to bring the asset to the location and condition necessary to be capable of operating in the manner intended by the Company, including eligible borrowing costs.

Depreciation of PP&E is recorded in the Statements of Comprehensive Income on a straight-line basis over the estimated useful life of the related asset. The estimated useful lives, residual values and depreciation methods are reviewed at the end of each annual reporting period, with the effect of any changes in estimate being accounted for on a prospective basis.

The estimated useful lives for PP&E are as follows:

Buildings and fixtures 10 - 50 years

Substations 15 - 60 years

Sub-transmission lines 45 - 60 years

Distribution system 40 - 60 years

Smart meters 15 years

Other capital assets 15 - 20 years

Land not depreciated

When parts of an item of property, plant and equipment have different useful

lives, they are accounted for as separate items

(major components) of property, plant and equipment

Major spare parts

Major spares such as spare transformers and other items kept as standby/back

up equipment are accounted for as PP&E since

they support the Company s distribution system reliability.

Contributions in aid of construction

When an asset is received as a capital contribution, the asset is initially

recognized at its fair value, with the corresponding

amount net of payments to the developer recognized as deferred revenue

(contributions in aid of construction).

Gains and losses on disposal

Gains and losses on disposal of an item of property, plant and equipment are

determined by comparing the net proceeds from

disposal with the carrying amount of the asset, and are included in the

Statement of Comprehensive Income when the asset is

disposed of. When an item of property, plant and equipment with related

Contributions in aid of construction is disposed, the

remaining deferred revenue is recognized in full in the Statement of

Comprehensive Income.

3.6 Borrowing costs

The Company capitalizes interest expenses and other finance charges directly
relating to the acquisition, construction or
production of assets that take a substantial period of time to get ready for
its intended use. Capitalization commences when
expenditures are being incurred, borrowing costs are being incurred and
activities that are necessary to prepare the asset for its
intended use or sale are in progress. Capitalization is suspended during
periods in which active development is interrupted and
ceases when substantially all of the activities necessary to prepare the asset
for its intended use or sale are complete.

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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3.7 Intangible assets

Computer software and land rights

Computer software that is acquired or developed by the Company, including
software that is not integral to the functionality of
equipment purchased, which has finite useful lives, is measured at cost less
accumulated amortization and accumulated
impairment losses.

Payments to obtain rights to access land ("land rights") are classified as
intangible assets. These include payments made for

easements, right of access and right of use over land for which the Company does not hold title. Land rights are measured at cost less accumulated amortization and accumulated impairment losses.

Amortization

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date.

The estimated useful lives for intangible assets are:

Land rights 40 years

Computer software 5 years

3.8 Impairment of non-financial assets

The Company conducts annual internal assessments of the values of property, plant and equipment, intangible assets and regulatory deferral account debit balances to determine whether there are events or changes in circumstances that indicate that their carrying amount may not be recoverable. Where the carrying value exceeds its recoverable amount, which is the higher of value in use and fair value less costs to sell, the asset is written down accordingly.

Where it is not possible to estimate the recoverable amount of an individual asset, the impairment test is carried out on the asset's cash-generating unit (CGU), which is the lowest group of assets to which the asset belongs for which there are separately identifiable cash inflows that are largely independent of the cash inflows from other assets. The entire Company is considered one cash-generating unit for which impairment testing is performed.

Name: **Orillia Power Distribution Corporation**

BN: **86512 0596 RC 0001**
Tax Year Start: **2015-01-01**
Tax Year End: **2015-12-31**

An impairment loss is charged to the Statement
of Comprehensive Income, except to the extent it reverses gains previously
recognized in other comprehensive income.
3.9 Provisions
A provision is recognized if, as a result of a past event, the Company has a
present legal or constructive obligation that can be
estimated reliably, and it is probable that an outflow of economic benefits
will be required to settle the obligation. Provisions are
determined by discounting the expected future cash flows at a pre-tax rate
that reflects current market assessments of the time
value of money and the risks specific to the liability.
3.10 Post-retirement benefits
Defined contribution plan
The employees of the Company participate in the Ontario Municipal Employees
Retirement System (OMERS). The Company
also makes contributions to the OMERS plan on behalf of its employees. The
plan has a defined benefit option at retirement
available to some employees, which specifies the amount of the retirement
benefit plan to be received by the employees based
on length of service and rates of pay. The Company is only one of a number of
employers that participates in the plan and the
financial information provided to the Company on the basis of the contractual
agreements is insufficient to measure the
Company s proportionate share in the plan assets and liabilities on defined
benefit accounting requirements. As insufficient
information is available to account for the plan as a defined benefit plan the
contribution payable in exchange for services
rendered during a period is recognized as an expense during that period.

3.10 Post-retirement benefits (continued)

Defined benefit plans

A defined benefit plan is a post-employment benefit plan other than a defined contribution plan. The Company s net obligation on behalf of its retired employees unfunded life insurance, extended medical and dental benefits is calculated by estimating the amount of future benefits that are expected to be paid out discounted to determine its present value. Any unrecognized past service costs are deducted.

The calculation is performed by a qualified actuary using the projected unit credit method every third year or when there are significant changes to workforce. When the calculation results in a benefit to the Company, the recognized asset is limited to the total of any unrecognized past service costs and the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. An economic benefit is available to the Company if it is realizable during the life of the plan, or on settlement of the plan liabilities.

Defined benefit obligations are measured using the projected unit credit method discounted to its present value using yields available on high quality corporate bonds that have maturity dates approximating to the terms of the liabilities. Remeasurements of the defined benefit obligation include actuarial gains and losses and are recognized directly within equity in other comprehensive income. Service costs are recognized in the Statement of Comprehensive Income in operating expenses, and include current and past service costs as well as gains and losses on curtailments.

Net interest expense is recognized the Statement of Comprehensive Income in finance expense, and is calculated by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the balance of the net defined benefit obligation, considering the effects of benefit payments during the period. Gains or losses arising from changes to defined benefits or plan curtailment are recognized immediately in the Statement of Comprehensive Income. Settlements of defined benefit plans are recognized in the period in which the settlement occurs.

Other long-term service benefits

Other employee benefits that are expected to be settled wholly within 12 months after the end of the reporting period are presented as current liabilities. Other employee benefits that are not expected to be settled wholly within 12 months after the end of the reporting period are presented as non-current liabilities and calculated using the projected unit credit method and then discounted using yields available on high quality corporate bonds that have

maturity dates approximating to the expected
remaining period to settlement.

3.11 Payment in lieu of taxes payable

Tax status

The Company is a Municipal Electricity Utility (MEU) for purposes of the
payments in lieu of taxes (PILs) regime contained in
the Electricity Act, 1998. As an MEU, the Company is exempt from tax under the
Income Tax Act (Canada) and the Corporations
Tax Act (Ontario).

Under the Electricity Act, 1998, the Company is required to make, for each
taxation year, PILs to the Ontario Electricity Financial
Corporation ("OEFC"), commencing October 1, 2001. These payments are
calculated in accordance with the rules for computing
taxable income and taxable capital and other relevant amounts contained in the
Income Tax Act (Canada) and the Corporation
Tax Act (Ontario) as modified by the Electricity Act, 1998, and related
regulations.

Current and deferred tax

Income tax expense is comprised of current and deferred tax. Current tax and
deferred tax are recognized in comprehensive
income except to the extent that it relates to items recognized directly in
equity or regulatory deferral account balances. Current
income taxes are recognized for the estimated income taxes payable or
receivable on taxable income for the current year and
any adjustment to income taxes payable in respect of previous years. Current
income taxes are determined using tax rates and
tax laws that have been enacted or substantively enacted by the year-end date.

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

3.11 Payment in lieu of taxes payable (continued)

Deferred tax assets and liabilities are recognized where the carrying amount of an asset or liability differs from its tax base. The amount of the deferred tax asset or liability is measured at the amount expected to be recovered from or paid to the taxation authorities. This amount is determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date and are expected to apply when the liabilities / (assets) are settled / (recovered). The Company recognized deferred tax arising from temporary difference on regulatory deferral account balances, post-retirement benefits and property, plant, equipment and intangible assets.

Recognition of deferred tax assets for unused tax losses, tax credits and deductible temporary differences is restricted to those instances where it is probable that future taxable profit will be available against which the deferred tax asset can be utilized.

At the end of each reporting period, the Company reassesses both recognized and unrecognized deferred tax assets. The Company recognizes a previously unrecognized deferred tax asset to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

3.12 Leased assets

Leases in terms of which the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Other leases are operating leases and the leased assets are not recognized on the Company's balance sheet. Payments made under operating leases are recognized in the Statement of Comprehensive Income on a straight-line basis over the lease term.

3.13 Finance income and finance costs

Finance income is comprised of interest income on funds invested such as cash and cash equivalents. Interest income is recognized as it accrues in the Statement of Comprehensive Income, using the effective interest method. Finance cost is comprised of interest payable on debt, post-retirement benefits and impairment losses recognized on financial assets.

3.14 Inventories

Cost of inventories comprise of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory on the basis of weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and

placed in inventory. Inventory is recognized at the
lower of cost and net realizable value.
Net realizable value is the estimated selling price in the ordinary course of
business less the estimated costs of completion and
the estimated costs necessary to make the sale.
3.15 Standards, amendments and interpretations not yet effective
At the date of authorization of these Financial Statements, certain new
standards, amendments and interpretations to existing
standards have been published by the IASB but are not yet effective, and have
not been adopted early by the Company.
Management anticipates that all of the relevant pronouncements will be adopted
in the Company s accounting policies for the first
period beginning after the effective date of the pronouncement. Information on
new standards, amendments and interpretations
that are expected to be relevant to the Company s Financial Statements is
provided below. Certain other new standards and
interpretations have been issued but are not expected to have a material
impact on the Company s Financial Statements.

Orillia Power Distribution Corporation
NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2015
(in thousands of Canadian dollars unless otherwise noted)

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3.15 Standards, amendments and interpretations not yet effective (continued)

IFRS 9 Financial Instruments replaces IAS 39 Financial Instruments: Recognition and Measurement

IFRS 9 amends the requirements for classification and measurement of financial assets, impairment, and hedge accounting.

IFRS 9 retains but simplifies the mixed measurement model and establishes three primary measurement categories for financial assets: amortized cost, fair value through profit or loss, and fair value through other comprehensive income. The basis of classification depends on the entity's business model and the contractual cash flow characteristics of the financial asset. The effective date for IFRS 9 is January 1, 2018. The Company is in the process of evaluating the impact of the new standard.

IFRS 15, Revenue from Contracts with Customers

IFRS 15 is based on the core principle to recognize revenue to depict the transfer of 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 or services. IFRS 15 focuses on the transfer of control. IFRS 15 replaces all of the revenue guidance that previously existed in IFRSs. The effective date for IFRS 15 is January 1, 2018. The Company is in the process of evaluating the impact of the new standard.

IFRS 16, Leases

IFRS 16 requires a lessee to recognize a right-of-use asset and a lease liability. The right-of-use asset is treated similarly to other non-financial assets and depreciated accordingly. The liability accrues interest. This will typically produce a front-loaded expense profile whereas operating leases under IAS 17 would typically have had straight-line expenses. The new Standard is effective for annual reporting periods beginning on or after January 1, 2019, with early application permitted but only if the entity is also applying IFRS 15, Revenue from contracts with customers. The Company is in the process of evaluating the impact of the new standard.

4. USE OF ESTIMATES AND JUDGEMENTS

The Company makes certain estimates and assumptions regarding the future. Estimates and judgements are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may differ from these estimates and assumptions. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Employee future benefits

The cost of post-employment life insurance, medical and dental benefits are determined using actuarial valuations. An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long term nature, post-employment medical and insurance benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date.

Payments in lieu of taxes payable

The Company is required to make payments in lieu of tax calculated on the same basis as income taxes on taxable income

earned. Significant judgement is required in determining the provision for
income taxes. There are many transactions and
calculations undertaken during the ordinary course of business for which the
ultimate tax determination is uncertain. The
Company recognizes liabilities for anticipated tax audit issues based on the
Company s current understanding of the tax law.
Where the final tax outcome of these matters is different from the amounts
that were initially recorded, such differences will
impact the current and deferred tax provisions in the period in which such
determination is made.

Orillia Power Distribution Corporation
NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2015
(in thousands of Canadian dollars unless otherwise noted)

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4. USE OF ESTIMATES AND JUDGEMENTS (continued)

Accounts receivable impairment

In determining the allowance for doubtful accounts, the Company considers
historical loss experience of account balances based
on the aging and arrears status of accounts receivable balances.

Regulatory deferral account debit and credit balances

In assessing the proper accounting treatment and determining the future
disposition of regulatory deferral account debit and
credit balances, the Company considers historical industry precedent and

follows the latest available and reliable guidance as

well as direction through written orders issued by the regulator.

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5. CASH AND CASH EQUIVALENTS

The Company s bank accounts are held with a Canadian chartered bank and earn

interest based upon its average monthly

balance at the bank s prime less 1.9%. Prime rate as of December 31, 2015 was

2.7% (December 31, 2014 3.0%, January 1,

2014 3%)

---

6. ACCOUNTS RECEIVABLE

Unaudited Unaudited

December 31 Decem ber 31 January 1

Accounts receivable 2015 2014 2014

$ $ $

Due from dis tribution cus tom ers 2 ,861 3 ,798 3,296

Recoverable work 298 275 186

Cons ervation and feed in tariff initiatives 193 106 30

Other 155 158 149

3 ,507 4 ,337 3,661

Allowance for doubtful accounts (88) (132)

(137)

3 ,419 4 ,205 3,524

ACCOUNTS RECEIVABLES BY AGE

0 - 60 days 3,143 3 ,933 3,406

61 - 90 days 19 22 10

Over 90 days 345 382 245

3 ,507 4 ,337 3,661

CONTINUITY OF ALLOWANCE FOR DOUBTFUL ACCOUNTS

Balance, beginning of year (132)

(137)

(151)

Bad debt expens e provis ion included in com prehens ive incom e (104)

(88) (93)

Written off 148 93 107

Balance, end of year (88) (132)

(137)

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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6. ACCOUNTS RECEIVABLE (continued)

Due to its short term nature, the carrying amount of the accounts receivable approximates its fair value.

7. UNBILLED ENERGY AND DISTRIBUTION REVENUE

Unbilled energy and distribution revenue represents amounts for which the Company has a contractual right to receive cash through future billings and are un-billed at year end. All accounts are billed on a monthly basis based on power consumed in the previous month. The amount of allowance for doubtful accounts that has been provided as at December 31, 2015 for unbilled revenues is $NIL (December 31, 2014 $NIL, January 1, 2014 $NIL) as they are considered current.

8. INVENTORIES

Unaudited Unaudited

December 31 Decem ber 31 January 1

Unbilled energy and distribution revenue 2015 2014 2014

$ $ $

Unbilled energy and dis tribution revenue 4 ,153 3 ,800 3,985

4 ,153 3 ,800 3,985

Unaudited

Inventories 2015 2014

$ $

Balance, beginning of year 526 618

Inventory purchas ed 399 497

Inventory us ed in:

Capital projects (capitalized) (246)

(400)

Operations and m aintenance (expens ed) (95) (104)

Recoverable work (82) (83)

Other adjus tm ents (1) (2)

Balance, end of year 501 526

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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9. PROPERTY, PLANT AND EQUIPMENT

Unaudited

Property, plant and equipment 2015 2014

$ $

COST

Balance, beginning of year 23,491 20,330

Purchas e of property, plant, equipm ent 2 ,269 3 ,190

Dis pos als (123)

(29)

Balance, end of year 25,637 23,491

ACCUMULATED DEPRECIATION

Balance, beginning of year 1 ,006 -

Depreciation 1 ,089 1 ,035

Dis pos als (44) (29)

Im pairm ent los s - -

Balance, end of year 2 ,051 1 ,006

CARRYING AMOUNTS

Balance, beginning of year 22,485 20,330

Purchas e of property, plant, equipm ent 2 ,269 3 ,190

Depreciation (1,089) (1,035)

Dis pos als (79) -

Im pairm ent los s - -

Balance, end of year 23,586 22,485

SUMMARY OF CARRYING AMOUNTS BY CATEGORY

Land and buildings 1 ,181 1 ,108

Dis tribution plant and equipm ent 21,524 20,399

Other 816 978

Work in progres s 65 -

Balance, end of year 23,586 22,485

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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10. INTANGIBLE ASSETS

Unaudited

Intangible assets 2015 2014

$ $

COST

Balance, beginning of year 200 137

Purchas e of intangibles 42 75

Dis pos als (34) (12)

Balance, end of year 208 200

ACCUMULATED AMORTIZATION

Balance, beginning of year 56 -

Am ortization 61 66

Dis pos als (34) (10)

Im pairm ent los s - -

Balance, end of year 83 56

CARRYING AMOUNTS

Balance, beginning of year 144 137

Purchas e of intangibles 42 75

Am ortization (61) (66)

Dis pos als - (2)

Im pairm ent los s - -

Balance, end of year 125 144

SUMMARY OF CARRYING AMOUNTS BY CATEGORY

Land rights 12 5

Com puter s oftware 113 139

Balance, end of year 125 144

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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11. REGULATORY DEFERRAL ACCOUNT BALANCES

All amounts deferred as regulatory deferral account debit balances are subject
to approval by the OEB. As such, amounts subject
to deferral could be altered by the regulators. Remaining recovery periods are
those expected and the actual recovery or
settlement periods could differ based on OEB approval. Carrying charges are
applied to deferral variance accounts unless
indicated otherwise using simple interest at the rate prescribed by the OEB

applied to monthly opening balances in the account

exclusive of accumulated interest.

11.1 Regulatory deferral account balances net of deferred income tax impacts

Due to previous, existing or expected future regulatory articles or decisions,

the Company has the following amounts expected to

be recovered by customers (returned to customers) in future periods and as

such regulatory deferral account balances are

comprised of net of deferred tax impacts:

Unaudited Unaudited

December 31 Decem ber 31 January 1

Regulatory deferral account balances 2015 2014 2014

Note $ $ $

REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES NET OF DEFERRED TAXES

Regulatory deferral account debit balances 11.3 2 ,893 2 ,138 2,626

Deferred tax im pact 767 540 696

2 ,126 1 ,598 1,930

REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES NET OF DEFERRED TAXES

Regulatory deferral account credit balances 11.3 4 ,064 2 ,927 3,806

Deferred tax im pact 1 ,077 772 1,009

2 ,987 2 ,155 2,797

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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11.2 Regulatory deferral account impacts on Statements of Comprehensive Income and Cash Flow

The following schedule summarizes the net movement in regulatory deferral account balances adjusted for related deferred tax impacts included in the Statement of Comprehensive Income and reducing profit for the year:

All of the above amounts are non-cash accruals added back to profit in order to arrive at cash flows from operating activities on the Statement of Cash Flow (see note 23). The following schedule summarizes the net movement in regulatory deferral account balances impacting cash and included in the investing activities section of the Statement of Cash Flow:

Unaudited

Net movement in regulatory balances including related deferred taxes 2015 2014

$ $

Regulatory debit reallocated from other incom e - change in PP&E us eful lives

(648)

(646)

Retail s ettlem ent variances between energy purchas ed and recovered from cus tom ers (254)

229

Los t revenue adjus tm ent reallocated from other revenue 170 57

Am ortization of s tranded m eters reallocated from other revenue (34) (34)

Settlem ent of PILs variance deferral account - (67)

Regulatory interes t and other - (9)

Net m ovem ent in regulatory balances before related deferred taxes (766)

(470)

Deferred taxes related to changes in regulatory balances 78 (81)

(688)

(551)

Unaudited

Changes in regulatory deferral account balances on cash flow statement 2015

2014

$ $

NET REGULATORY DEFERRAL ACCOUNT BALANCES

Regulatory deferral account debit balances 2 ,893 2 ,138

Regulatory deferral account credit balances 4 ,064 2 ,927

Net regulatory deferral account debit (credit) balances (1,171) (789)

CHANGES IN REGULATORY DEFERRAL ACCOUNT BALANCES (CASH FLOW STATEMENT)

Net change in deferral account debit (credit) balances 382 (391)

Net m ovem ent in regulatory balances before related deferred taxes (766)

(470)

Other - (14)

Changes in regulatory deferral account balances - cash flow (384)

(875)

RECONCILED TO ABOVE AS FOLLOWS:

Dis pos ition of approved regulatory deferral account balances (397)

(875)

Other (13) -

Changes in regulatory deferral account balances - cash flow (384)

(875)

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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11.3 Detail for regulatory deferral account balances

Regulatory deferral account debit balances are comprised of the following

accounts:

Regulatory deferral account credit balances are comprised of the following

accounts:

Unaudited Unaudited

December 31 Decem ber 31 January 1

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

Regulatory deferral account debit balances 2015 2014 2014

Account #'s $ $ $

Low voltage 1550 887 399 522

Stranded m eter capital 1555 274 308 342

Paym ent in lieu of taxes 1563 20 20 88

Los t revenue variance 1568 299 122 61

Network s ervices - trans m is s ion 1584 66 58 316

Connection s ervices - trans m is s ion 1586 54 - 199

Power 1588 146 272 -

Global adjus tm ent 1589 1 ,131 932 1,068

Other regulatory deferral account debit balances 16 27 30

2 ,893 2 ,138 2,626

Unaudited Unaudited

December 31 Decem ber 31 January 1

Regulatory deferral account credit balances 2015 2014 2014

Account #'s $ $ $

Retail cos ts 1518 / 1548 63 59 54

IFRS - CGAAP Trans itional PP&E am ounts 1575 14 14 -

Change in PP&E us eful lives es tim ates 1576 1 ,936 1 ,288 642

Dis pos ition / recoveries 1595 19 405 242

Wholes ale m arket s ervices 1580 2 ,032 1 ,110 2,211

Connection s ervices - trans m is s ion 1586 - 51 -

Power 1588 - - 657

4 ,064 2 ,927 3,806

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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11.4 Continuity schedules for regulatory deferral account balances

A continuity schedule from 2014 to 2015 for regulatory deferral account debit balances follows below:

A continuity schedule from 2014 to 2015 for regulatory deferral account credit balances follows below:

11.5 Description of regulatory deferral account balances

A description of the nature of the regulatory deferral account debit and credit balances listed in the schedules are described below referenced by account number.

Account 1518 - Retail Cost Variance Account Services

This account records the net of revenue derived from establishing retail service agreements, distributor-consolidated and retailer-consolidated billing and the costs of entering into retail service agreements and related administration, monitoring and other expenses necessary to maintain the contract, as well as the incremental costs incurred and any avoided costs credits to provide the related billing services.

Unaudited

De ce m be r 31 December 31

Regulatory deferral account debit balances 2015 2014

Account #'s $ $ $ $

Low voltage 1550 1 - 4 887 - 488 399

Stranded m eter capital 1555 1 - 4 274 (34)

- 308

Paym ent in lieu of taxes 1563 1 - 4 2 0 - - 2 0

Los t revenue variance 1568 1 - 4 299 - 177 122

Network s ervices - trans m is s ion 1584 1 - 4 6 6 - 8 5 8

Connection s ervices - trans m is s ion 1586 1 - 4 5 4 - 54 -

Power 1588 1 - 4 146 - (126) 272

Global adjus tm ent 1589 1 - 4 1,131 - 199 932

Other regulatory deferral account debit balances 1 - 4 1 6 (14)

3 2 7

2,893 (48)

803 2,138

Balances

arising in the

period

Recovery /

Reversal

Est. Yrs

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

to Rec /

Reverse

Unaudited

De ce m be r 31 December 31

Regulatory deferral account credit balances 2015 2014

Account #'s $ $ $ $

Retail cos ts 1518 / 1548 1 - 4 6 3 - 4 5 9

IFRS - CGAAP Trans itional PP&E am ounts 1575 1 - 4 1 4 - - 1 4

Change in PP&E us eful lives es tim ates 1576 1 - 4 1,936 - 648 1,288

Dis pos ition / recoveries 1595 1 1 9 - (386) 405

Wholes ale m arket s ervices 1580 1 - 4 2,032 - 922 1,110

Connection s ervices - trans m is s ion 1586 1 - 4 - - (51) 5 1

Power 1588 1 - 4 - - - -

4,064 - 1,137 2,927

Est. Yrs

to Rec /

Reverse

Balances

arising in the

period

Recovery /

Reversal

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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11.5 Description of regulatory deferral account balances (continued)

Account 1548 - Retail Cost Variance Account STR

This account records the net of revenue derived from service transaction requests (STR) in the form of a request fee, processing fee, and information request fee and the incremental cost of labour, internal information system maintenance costs and delivery costs related to the provision of these services.

Account 1550 Low Voltage Charges Variance Account

This account records the net of revenue derived from amounts billed to customers through an OEB-approved rate for low voltage services and the amounts paid to Hydro One Networks Inc. for the related low voltage services provided to Orillia Power Distribution Corporation (OPDC).

Account 1555 Stranded Meters Account

Conventional meters were replaced by smart meters during the smart meter deployment from 2009 to 2011 and OPDC recorded the disposition of these stranded assets in Property, Plant & Equipment and a regulatory deferral debit balance in accordance with OEB Guidelines. This account records the net book value of the stranded conventional meters, to be amortized to depreciation expense until the next cost of service rate application. Carrying charges are not applied to this account.

Account 1563 Residual PILs Contra Account

This account represents the residual amount remaining after the disposition of variances resulting from the true-up between certain proxy amounts used to set Payments in Lieu of Tax (PILs) rates and the actual amount of PILS paid for the period 2001 through April 30, 2006. The OEB approved disposition on a final basis from May 1, 2012 to April 30, 2014.

Account 1568 LRAM Variance Account

The OEB established a Lost Revenue Adjustment Mechanism variance account (LRAMVA) to capture the differences between the results of actual, verified impacts of authorized Conservation and Demand Management (CDM) activities undertaken by electricity distributors from 2011 to 2014 and the level of CDM program activities included in the distributor s load forecast (i.e. the level embedded into rates). Lost revenues are recorded annually and are included in the net movement in regulatory deferral account balances on the statement of comprehensive income. OPDC has proposed disposition of LRAMVA amounts related to CDM programs up to December 31, 2014 in its 2016 incentive rate-setting mechanism (IRM) application. On March 3, 2016, the OEB announced that the LRAMVA balance included in OPDC s application will not be disposed of until the completion of a generic review of how demand savings should be reflected in the LRAMVA account, leaving the status of OPDC s claim uncertain as of the date of the financial statements.

Account 1575 IFRS-CGAAP Transitional PP&E Amounts

This account records the property, plant and equipment difference arising as a

result of an accounting policy change recognizing
capital contributions as deferred revenue upon transition from previous
Canadian GAAP to IFRS on January 1, 2014. The
balance in this account represents the amortization of the transition year
capital contributions previously expensed in 2014. The
associated net book value is recorded as deferred revenue and will be
amortized to income over a period that matches the
remaining useful lives of the related fixed assets. Carrying charges are not
applied to this account.

Account 1576 Accounting Changes under CGAAP

This account records the financial differences arising as a result of changes
OPDC made to accounting depreciation under
CGAAP effective January 1, 2013. OPDC adopted new asset useful lives based on
the 2010 Kinectric s Report , part of an asset
depreciation study initiated by the OEB for use by electricity distributors.
Carrying charges are not applied to this account.

Orillia Power Distribution Corporation
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(in thousands of Canadian dollars unless otherwise noted)

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11.5 Description of regulatory deferral account balances (continued)

Account 1580 Retail Settlement Variance Account - Wholesale Market Services

This account records the net of revenue derived from amounts billed to

consumers through an OEB-approved rate for the cost of
services required to operate the provincial electricity system and run the
wholesale market and the amounts paid to the IESO for
these system costs.

Account 1584 Retail Settlement Variance Account Retail Transmission
Network Services

This account records the net of revenue derived from amounts billed to
consumers through an OEB-approved rate for retail
transmission network services and the amounts paid to Hydro One Networks Inc.
for the related network costs.

Account 1586 Retail Settlement Variance Account Retail Transmission
Connection Services

This account records the net of revenue derived from amounts billed to
consumers through an OEB-approved rate for retail
transmission connection services and the amounts paid to Hydro One Networks
Inc. for the related connection costs.

Account 1588 Retail Settlement Variance Account Power

This account records the net of revenue derived from amounts billed to
consumers for electricity costs and the amounts paid to
the IESO and embedded generators for electricity purchased. OPDC purchases
power on behalf of the customer and passes
these costs on to the customer with no markup. This account captures variances
due to theft of power and unaccounted-for
energy as well as the difference between estimated and actual distribution
line losses.

Account 1589 Retail Settlement Variance Account Global Adjustment

This account records the net of revenue derived from amounts billed to non-
Regulated Price Plan (non-RPP) consumers for

global adjustment costs and an allocation of amounts paid to the IESO for
global adjustment charged on electricity purchased for
non-RPP consumers. This account captures variances due to the timing of bills
and difference between global adjustment rates
billed to consumers and final charges billed to OPDC each month.

Account 1595 Disposition of Regulatory Account Balances

This account records the net of the disposition of regulatory deferral account
balances approved for recovery (or refund) in rates
as part of the regulatory process and the amounts recovered (or refunded)
through OEB-approved regulatory deferral account
rate riders from the following OEB applications:

OPDC filed an IRM application on October 31, 2011 for 2012 distribution rates
(EB-2011-0191). On April 19, 2012, the OEB
approved the disposition of regulatory deferral debits of $843 and regulatory
deferral credits of $1,898 over a two year period May
1, 2012 to April 30, 2014. The net disposition balance of $1,055 consisted of
principal balances as of December 31, 2010 with
carrying charges projected to April 30, 2012.

OPDC filed an IRM application on October 11, 2013 for 2014 distribution rates
(EB-2013-0161). On April 24, 2014, the OEB
approved the disposition of regulatory deferral debits of $1,236 and
regulatory deferral credits of $2,280 over a one year period
May 1, 2014 to April 30, 2015. The net disposition balance of $1,044 consisted
of principal balances as of December 31, 2012
with carrying charges projected to April 30, 2014.

Orillia Power Distribution Corporation

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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11.6 2016 Rate Applications

OPDC filed an application on October 19, 2015 for 2016 distribution rates (EB-2015-0286) seeking to establish a rate adder for the disposition of the balance in regulatory deferral credit account 1576 - Accounting Changes under CGAAP as of December 31, 2014. On January 14, 2016, the OEB approved on an interim basis the disposition of a regulatory deferral credit balance of $1,481 over a one year period January 1, 2016 to December 31, 2016. The approved disposition represents the balance in the account plus a rate of return component according to OEB filing requirements for cost of service applications. No carrying charges have been applied. OPDC will seek final disposition of this regulatory deferral credit balance at the time of its next cost of service application.

OPDC filed an IRM application on October 19, 2015 for 2016 distribution rates (EB-2015-0024) which included a request seeking disposition of the balances for regulatory deferral balances. On March 17, 2016, the OEB approved the disposition of regulatory deferral debits of $1,690 and regulatory deferral credits of $1,198 over a one year period May 1, 2016 to April 30, 2017. The net disposition balance of $492 consists of principal balances as of December 31, 2014 with carrying charges projected to April 30,

2016. OPDC s application included a request for disposition of an LRAMVA balance of $299 based on an estimate at the time of filing which has not been approved at the time of the financial statements, and is subject to a pending OEB generic review of how demand savings should be reflected in the LRAMVA accounts for all distributors.

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12. BANK INDEBTEDNESS

The Company has credit facilities currently negotiated with a Canadian chartered bank. The facilities are subject to the borrower meeting certain covenant thresholds in order to pay dividends without bank permission. The agreement also includes financial covenants related to debt service coverage ratios and debt to capitalization ratios that must be met by the borrower. The Company is in compliance with all covenant requirements. Facilities are as follows:

OPDC **-** committed revolving operating loan available at the borrower s option by way of prime based loans, banker s acceptances and standby letters of guarantee (L/G), utilized to finance ongoing working capital requirements and any prudential letter of guarantee requirements. The operating loan is secured with a General Security Agreement on the assets of OPDC. Cash advances are at prime less 0.25% with a standby fee for the unused portion at 0.15%. L/Gs are issued at a cost of 0.50% per annum.

OPDC **-** committed reducing term (multiple draw) loan available at the borrower s option by way of fixed rate terms up to five

years and floating prime based loans. Utilized to finance prior year capital
expenditures and replenish working capital. The
operating loan is secured with a General Security Agreement on the assets of
OPDC. Cash advances are at prime less 0.25%
with a standby fee for the unused portion at 0.15%. Currently, draws on this
facility are interest only and have not been locked in
to a fixed term or rate.

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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12. BANK INDEBTEDNESS (continued)

The following table outlines facilities available and utilized:

13. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Due to its short term nature, the carrying amount of the accounts payable and
accrued liabilities approximates its fair values.

Unaudited Unaudited

December 31 Decem ber 31 January 1

Bank indebtedness 2015 2014 2014

$ $ $

BORROWING LIMITS ON CREDIT FACILITIES AVAILABLE

OPDC - revolving operating loan for working capital purpos es 5 ,000 5 ,000 5

,000

OPDC - com m itted reducing term facility for capex 5 ,000 5 ,000 5 ,000

10,000 10,000 10,000

CASH AMOUNTS BORROWED AND OUTSTANDING

OPDC - revolving operating loan for working capital purpos es - 200 950

OPDC - com m itted reducing term facility for capex 2 ,000 - -

2 ,000 200 950

IRREVOCABLE LETTERS OF CREDIT OUTSTANDING

OPDC - revolving operating loan for working capital purpos es 2 ,035 2 ,035 2

,035

OPDC - com m itted reducing term facility for capex - - -

2 ,035 2 ,035 2,035

Unaudited Unaudited

December 31 Decem ber 31 January 1

Accounts payable and accrued liabilities 2015 2014 2014

$ $ $

Power purchas es 2 ,774 2 ,961 2,665

Accounts payable and accrued 2 ,161 2 ,727 2,220

Cus tom er credit balances 824 979 837

5 ,759 6 ,667 5,722

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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14. CURRENT AND DEFERRED INCOME TAXES (PILS)

14.1 Current income tax expense included in Statement of Comprehensive Income

Combined statutory federal and provincial tax rates for Ontario are 26.5% on

active business. Income tax expense varies from

amounts which would be computed by applying the Company s combined statutory

income tax rate as follows:

14.2 Payments in lieu of taxes receivable (payable)

Unaudited

Current provision 2015 2014

$ $

Profit for the year after net m ovem ent in regulatory deferral account

balances 873 1 ,217

Add back provis ion for paym ent in lieu of taxes 476 259

1 ,349 1 ,476

Statutory federal and provincial com bined rate 26.5% 26.5%

Provis ion for PILS at s tatutory rates 357 391

Increas e (decreas e) in PILS res ulting from differences in tax bas e vs carrying values :

Property plant and equipm ent and cum ulative eligible capital (157)

(188)

Regulatory deferral account balance changes 107 (83)

Other 15 (46)

322 74

Unaudited Unaudited

December 31 Decem ber 31 January 1

Payment in lieu of taxes receivable and payable 2015 2014 2014

$ $ $

Paym ent in lieu of taxes receivable - - 355

Paym ent in lieu of taxes payable (217)

- -

(217)

- 355

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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14. CURRENT AND DEFERRED INCOME TAXES (PILS) (continued)

14.3 Deferred income tax expense included in Statement of Comprehensive Income

Deferred income taxes recognized in the Statement of Comprehensive Income are
as follows:

14.4 Deferred income tax assets

Deferred income tax assets are provided for temporary differences between the
financial statement carrying values of existing
assets and liabilities and their respective tax bases. The following table
outlines the Company s position with respect to deferred
tax assets. The utilization of this tax asset is dependent on future taxable
profits in excess of profits arising from the reversal of
existing taxable temporary differences. The Company believes that this asset
should be recognized as it will be utilized through
future activities.

Unaudited

Deferred provision 2015 2014

$ $

Included in profit for the year

Property, plant, equipm ent and intangibles 157 188

Pos t-retirem ent benefits and s ick pay accrual (3) (3)

154 185

Included in other comprehensive profit for the year

Pos t-retirem ent benefits and s ick pay accrual - 33

- 33

Unaudited Unaudited

December 31 Decem ber 31 January 1

Deferred income tax asset and liabilities 2015 2014 2014

$ $ $

Asset (liability) due excess (shortfall) of tax basis over carrying value:

Property, plant, equipm ent and intangibles 894 1 ,051 1,239

Pos t-retirem ent benefits 172 169 199

Sick pay accrual 13 13 13

1 ,079 1 ,233 1,451

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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14. CURRENT AND DEFERRED INCOME TAXES (PILS) (continued)

14.5 Deferred tax balances related to regulatory deferral accounts

Deferred tax balances related to regulatory deferral account debit and credit balances are netted against the applicable regulatory deferral account debit or credit balances. They are not included with the other deferred income tax asset balances related to property, plant, equipment, intangibles, post-retirement benefits and loss carry forward.

15. CUSTOMER SECURITY DEPOSITS

Customer deposits represents cash deposits from electricity distribution customers and retailers, as well as construction deposits from customers and developers. Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service. Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to contributions in aid of construction.

Unaudited Unaudited

December 31 Decem ber 31 January 1

Deferred income tax assets (liabilities) included with regulatory balances

2015 2014 2014

$ $ $

Asset (liability) due excess (shortfall) of tax basis over carrying value:

As s et included with regulatory deferral account credit balances 1 ,077 772

1,009

Liability included with regulatory deferral account debit balances (767)

(540)

(696)

310 232 313

Unaudited Unaudited

December 31 Decem ber 31 January 1

Customer security deposits 2015 2014 2014

$ $ $

Cus tom er depos its 313 289 259

Cons truction depos its 140 56 50

453 345 309

Allocated to:

Current 133 68 71

Long term 320 277 238

453 345 309

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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16. POST RETIREMENT BENEFITS

Defined contribution plan

The employees of the Company participate in the Ontario Municipal Employees

Retirement System (OMERS). Although the plan has a defined retirement benefit plan for employees, the related obligation of the corporation cannot be identified. The OMERS plan has several unrelated participating municipalities and costs are not specifically attributed to each participant. The employer portions of amounts paid to OMERS were made for current service and recognized in comprehensive income are as follows:

Defined benefit plan
The Company provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. These benefits are provided through a group defined benefit plan. The Company has reported its share of the defined benefit costs and related liabilities, as calculated by an actuary, in these Financial Statements.
The accrued benefit liability and the expense for the years ended December 31, 2015 and 2014 were based on results and assumptions determined by actuarial valuation as at December 31, 2014 and are as follows:

The plan is exposed to a number of risks, including:
? Interest rate risk: decreases/increases in the discount rate used (high quality corporate bonds) will increase/decrease the defined benefit obligation.
? Longevity risk: changes in the estimation of mortality rates of current and former employees.
? Health care cost risk: increases in cost of providing health, dental and life insurance benefits.

Unaudited

Contributions to OMERS on behalf of employees 2015 2014

$ $

360 337

Unaudited

December 31 Decem ber 31

Post-retirement benefits 2015 2014

$ $

Defined benefit obligation, beginning of year 637 752

Am ounts recognized in profit for the year

Current s ervice cos ts 11 8

Finance cos ts on obligation 24 29

35 37

Benefit paym ents (27) (29)

Experience gains (los s es) included in other com prehens ive los s 3 (123)

Defined benefit obligation, end of year 648 637

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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16. POST RETIREMENT BENEFITS (continued)

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

Assumptions used in the actuarial valuation in order to determine the present

value of the unfunded obligation are as follows:

17. DEFERRED REVENUE

Deferred revenue consists of capital contributions received from developers

during the construction and acquisition of distribution

property, plant and equipment which has not yet been recognized into other

revenue. Such capital contributions are recorded as

deferred revenue and recognized to other revenue over the life of the related

assets as follows:

Unaudited

December 31 Decem ber 31

Assumptions used in actuarial valuation 2015 2014

Dis count rate 3.9% 3.9%

Cons um er price index 2.0% 2.0%

Com pens ation increas e 2.0% 2.3%

Health cos t increas es 4.6% 4.6%

Dental cos t increas e 4.8% 4.6%

Retirem ent age 58 58

Unaudited

Deferred revenue 2015 2014

$ $

Balance, beginning of year 1 ,060 -

Contributions in aid of cons truction received 135 1 ,074

Contributions in aid of cons truction am ortized to other revenue (29) (14)

Balance, end of year 1 ,166 1 ,060

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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18. LONG TERM DEBT

Promissory notes payable to City of Orillia

The promissory notes payable to the City of Orillia, the shareholder of Orillia Power Corporation, the parent Company, bear interest for the current year at 6.25% per annum (December 31, 2014 6.25%, January 1, 2014 - 6.25%). The interest rate is reviewed annually and payments of interest are required to be made quarterly on the last day of March, June, September and December. The promissory notes are due December 31, 2030 and payments to the City of Orillia are interest only. Under the terms of the notes, the City of Orillia can demand repayment of up to 20% of the original principal in a calendar year with the payment to be made March 31 provided the City gives six months notice to the

Company. No such demand has been made by
the City as of the date of approval of these financial statements. The fair
value of the notes at current market borrowing rates
approximates $11,256. The notes are secured by a general security agreement on
all the assets of the Company.
Debenture payable to Infrastructure Ontario
The Company has entered into a financing arrangement with Ontario
Infrastructure Projects Corporation (OIPC), to provide
debenture financing for its smart meter infrastructure expenditures. On May 3,
2010 a debenture in the amount of $2,100 was
issued based on a 10-year term and an annual interest rate of 4.39%. The
Company incurred $48 (2014 - $57) in interest
expense to OIPC in 2015. Under the terms of the debenture, the Company must
make principal repayments of $210 annually,
until the debenture is retired in 2020. The financing arrangement grants OIPC
a general security agreement against the
Company, in third priority behind the Toronto Dominion Bank and the City of
Orillia. The agreement restricts dividends paid by
Orillia Power Distribution Corporation to amounts that meet the definition of
Permitted Distributions unless waived by OIPC.

Unaudited Unaudited
December 31 Decem ber 31 January 1
Long term debt 2015 2014 2014
$ $ $
Prom is s ory note due to City of Orillia - OPDC 9 ,762 9 ,762 9 ,762

Ontario Infras tructure Projects Corporation ("OIPC") 945 1 ,155 1 ,365

10,707 10,917 11,127

Current portion of OIPC long term debt 210 210 210

10,497 10,707 10,917

Principal repayments anticipated over the next five years and thereafter:

2014 - - 210

2015 - 210 210

2016 210 210 210

2017 210 210 210

2018 210 210 210

2019 210 210 210

2020 105 105 105

Thereafter 9 ,762 9 ,762 9 ,762

10,707 10,917 11,127

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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19. SHARE CAPITAL

Nature and purpose of equity

The reserves recorded in equity on the Company s Statement of Financial

Position include Share capital and Retained

earnings . Share capital is used to record the issuance of equity. Retained earnings is used to record the Company s change in

retained earnings from year to year.

Share capital

An unlimited number of common shares with no par value are authorized for

issue. All shares are ranked equally with regards to

the Company's residual assets and there was no change in share capital during

2015 and 2014. The Company does not have

preference shares.

20. OPERATING REVENUE

Unaudited Unaudited

December 31 Decem ber 31 January 1

Share capital 2015 2014 2014

$ $ $

Share capital 8 ,236 8 ,236 8,236

8 ,236 8 ,236 8,236

Issued and fully paid:

Com m on s hares 1 ,001 1 ,001 1,001

Unaudited

Operating revenue 2015 2014

$ $

Dis tribution revenue 7 ,857 8 ,048

Other revenue 678 605

8 ,535 8 ,653

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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21. OPERATING EXPENSES

22. FINANCE INCOME AND FINANCE COSTS

Unaudited

Operating expenses 2015 2014

$ $

EXPENSES BY NATURE

Board and s taff cos ts 2 ,678 2 ,798

Operations and m aintenance 711 745

General adm ins tration and overhead 1 ,088 947

Bad debts 104 88

Donations 268 20

4 ,849 4 ,598

EXPENSES BY FUNCTION

Operations and m aintenance 1 ,980 2 ,074

Billing and collection 1 ,160 1 ,099

Adm inis tration and general 1 ,709 1 ,425

4 ,849 4 ,598

Unaudited

Finance income and finance costs 2015 2014

$ $

FINANCE INCOME

Recognized in profit or loss:

Interes t incom e on bank depos its 8 14

8 14

FINANCE COSTS

Recognized in profit or loss:

Interes t on City prom m is ory notes 610 610

Interes t on non-related debt 48 57

Interes t on pos t retirem ent benefits 24 29

682 696

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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23. NON-CASH OR NON-OPERATING ADJUSTMENTS INCLUDED IN PROFIT OR LOSS

In order to arrive at cash flows from operating activities on the Statement of
Cash Flows the following items need to be added or
subtracted from profit for the year:

---

24. NET CHANGES IN NON-CASH WORKING CAPITAL

Unaudited

Other non-cash or non-operating items included in profit 2015 2014

$ $

NON-REGULATORY ITEMS (NON-CASH OR NON-OPERATING)

Paym ents in lieu of taxes included in profit and los s 476 259

Los s on dis pos al of property, plant and equipm ent 79 16

Am ortization of deferred revenue (29) (14)

Pos t-retirem ent benefits 11 8

Finance incom e (8) (14)

Finance expens e 682 696

1 ,211 951

REGULATORY ITEMS (NON-CASH)

Net m ovem ent in regulatory balances including related deferred taxes 688 551

688 551

1 ,899 1 ,502

Unaudited

Net changes in non-cash working capital 2015 2014

$ $

Accounts receivable 786 (681)

Unbilled energy and dis tribution revenue (353)

185

Paym ent in lieu of taxes receivable - 355

Inventories 25 92

Prepaid expens es 25 (29)

Due from related parties (99) 59

Bank indebtednes s to finance working capital requirem ents (200)

(750)

Accounts payable and accrued liabilities (908)

945

Paym ent in lieu of taxes payable 217 -

Cus tom er s ecurity depos its 65 (3)

Due to related parties (2) 57

(444)

230

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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25. RELATED PARTY TRANSACTIONS

The ultimate parent

The common shares of Orillia Power Corporation are owned by the Corporation

the City of Orillia, the ultimate parent, which

constitutes a local government. Consequently, the Company is exempt from some

of the general disclosure requirements of IAS

24 with relation to transactions with government-related parties, and has

applied the government-related disclosure requirements.

Orillia Power Corporation is the 100% owner of Orillia Power Distribution

Corporation and Orillia Power Generation Corporation.

Key management personnel compensation

Key management personnel are defined in IAS 24 as those persons having

authority and responsibility for planning, directing

and controlling the activities of the entity, directly or indirectly,

including any director (whether executive or otherwise) of that

entity . Key management personnel of the Company have been defined as members

of its board of directors, officers and senior

managers reporting directly to the President and Chief Executive Officer.

Unaudited

Key management personnel compensation 2015 2014

$ $

Board of directors 69 51

Officers and s enior m anagers 447 539

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001
Tax Year Start: 2015-01-01
Tax Year End: 2015-12-31

516 590

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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25. RELATED PARTY TRANSACTIONS (continued)

Transactions with related parties

The Company provides electricity and other services to the Corporation of the City of Orillia (City). The Company also purchases services and pays rent, property taxes, interest and dividends to the City. The Company has a shared services agreement with Orillia Power Generation Corporation. The control centre, building space, purchasing and administrative staff are shared among the two companies under specific affiliate relationships code exemptions.

Unaudited

Related party transactions 2015 2014

$ $

Financing activities with The Corporation of the City of Orillia ("City")

Finance cos ts paid to the City 610 610

Operating activities with The Corporation of the City of Orillia ("City")

Power s old to the City 2 ,339 2 ,236

Other s ervices s old to the City 128 79

Goods and s ervices purchas ed from the City 69 80

Property taxes paid to the City 70 67

Balances outstanding with The Corporation of the City of Orillia ("City")

Due from City included in receivables 224 293

Due to City included in payables 9 157

Investing and financing activities with affiliates

Dividends paid to parent 1 ,230 -

Operating activities with affiliates - sold to

Goods and s ervices s old to Orillia Power Corporation 6 8

Goods and s ervices s old to Orillia Power Generation 1 ,049 950

Operating activities with affiliates - purchased from

Goods and s ervices purchas ed from Orillia Power Corporation 69 51

Goods and s ervices purchas ed from Orillia Power Generation 122 166

Due from related parties

Due from Orillia Power Generation 863 768

Due from s olar s ubs idiary 4 -

Due to related parties

Due to Orillia Power Corporation 55 57

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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26. COMMITMENTS AND CONTINGENCIES

IESO prudential security commitments

Purchasers of electricity in Ontario, through the Independent Electricity Systems Operator (IESO), are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by default notice issued by the IESO. As at December 31, 2015, the Company has provided prudential support to the IESO in the form of an irrevocable, automatically renewing bank letter of credit in the amount of $2,035 (December 31, 2014 - $2,035, January 1, 2014 - $2,035).

Donation commitment

In 2012, Orillia Power Corporation pledged to make a donations of $1,250 payable over five years to the local hospital foundation. Total payments of $1,000 have now been made by companies within the corporate entity towards this pledge. The Board of Directors has authorized Orillia Power Distribution Corporation to make the last payment of $250 prior to July 2016 at which time the commitment to the hospital foundation will have been 100% fulfilled.

Membership commitment

In 2015, a subsidiary of the Company renewed a three year membership commitment in the Cornerstone Hydro Electric Concepts Association Inc. (CHEC), an association of approximately fifteen distributors modelled after a co-operative to share resources and proficiencies. The subsidiary can terminate its membership by

giving sixty days notice and paying the unpaid
balance of its three year commitment. As of December 31, 2015 the cost to
terminate the membership is approximately $81.

Liability insurance

The Company and its subsidiaries belong to the Municipal Electric Association
Reciprocal Insurance Exchange (MEARIE), a
self-insurance plan designed to pool all member risks. Any losses experienced
by MEARIE are shared amongst all of its
members. As of the date of Board of Directors approval of this financial
report, the corporation has not been made aware of any
assessments for significant losses. The Company and its subsidiaries have
contracted for a maximum total of $24 million in event
coverage with MEARIE and $10 million in excess liability coverage with a
secondary provider.

Legal proceeding contingencies

In 2012, a legal proceeding was commenced against the Company related to
damages to Bell Canada property. The Company
has turned this matter over to its liability insurer and the matter is
currently before the Ontario Superior Court of Justice. At this
time, it is not possible to quantify the effect, if any, on the financial
statements of the Company. Management does not believe
that the outcome of this matter will have a material impact on the financial
statements.

In relation to a 2013 motor vehicle accident, a legal proceeding has been
commenced against the Company. This matter has
been turned over to the Company s liability insurer and is currently before
the Ontario Superior Court of Justice. At this time, it is
not possible to quantify the effect, if any, on the financial statements of

the Company. Management does not believe that the
outcome of this matter will have a material impact on the financial
statements.

Orillia Power Distribution Corporation
NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2015
(in thousands of Canadian dollars unless otherwise noted)

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27. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT
As part of its operations, the Company carries out transactions that expose it
to financial risks such as credit, liquidity and market
risks. The following is a discussion of risks and related mitigation
strategies that have been identified by the Company for
financial instruments. This is not an exhaustive list of all risks, nor will
the mitigation strategies eliminate all risks identified.
Cash and cash equivalents are measured at fair value. The carrying values of
receivables, and accounts payable and accrued
charges approximate fair value because of the short maturity of these
instruments.
Credit risk
Financial assets carry credit risk that a counter-party will fail to discharge
an obligation which would result in a financial loss.

Financial assets held by the Company, such as accounts receivable, expose it
to credit risk. The Company earns its revenue
from a broad base of approximately 13,500 customers located in the City of
Orillia. No single customer accounts for revenue in
excess of 10% of total revenue. The carrying amount of accounts receivable is
reduced through the use of an allowance for
impairment. The amount of the related impairment loss is recognized in the
statement of profit or loss as are any subsequent
recoveries of receivables previously provisioned. Further details on accounts
receivable can be found in other notes to these
financial statements.
Credit risk is managed through collection of security deposits from customers
in accordance with OEB codes and regulations.
Further details on customer security deposits can be found in other notes to
these financial statements.
Market risk
The Company is not exposed to significant market risk given they do not have
investments in foreign currency, and have minimal
investment in interest bearing instruments.
Liquidity risk
Liquidity risk is the risk that the Company will not be able to meet its
financial obligations as they come due. The Company
monitors its liquidity risk to ensure access to sufficient funds to meet
operational and investing requirements. The Company's
objective is to ensure that sufficient liquidity is on hand to meet
obligations as they fall due while minimizing interest exposure.
The Company has access to various operating lines of credit and monitors cash
balances to ensure that sufficient levels of

liquidity are on hand to meet financial commitments as they come due. Further details on accounts payable and accrued liabilities can be found in other notes to these financial statements.

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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28. CAPITAL MANAGEMENT

The Company considers its capital to be its share capital, accumulated retained earnings and accumulated other comprehensive income (loss). The Company s objectives when managing capital are:

? to safeguard the Company's ability to continue as a going concern, so that it can continue to provide adequate returns for shareholders and benefits for other stakeholders while maintaining its assets, and

? to provide an adequate return to shareholders by controlling costs and establishing rates that maximize rate of return commensurate with the level of risk, and

? to ensure the capital structure does not prevent the Company from taking advantage of potential growth opportunities provided that they do not expose the Company to unnecessary risk.

The Company manages its capital structure and makes adjustments to it in light
of changes in economic conditions, annual
profitability and the risk characteristics of the underlying assets. In order
to maintain or adjust the capital structure, the Company
will adjust the amount of dividends paid to shareholders, subject to the
constraints imposed by lending agreements. The
Company is subject to quarterly reporting and bank review of its interest
coverage and debt capitalization ratios, in relation to its
various bank credit lines.
Consistent with others in the industry, the Company monitors capital on the
basis of the debt-to-capital ratio calculated as long
term debt divided by the sum of long term debt plus equity, as shown in the
following table. For purposes of comparing the
measures below to benchmarks, the Company was initially incorporated at a debt
to capital ratio of 0.48.

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29. FIRST TIME ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS
IFRS 1, First Time Adoption of International Financial Reporting Standards,
requires that comparative financial information be
provided. As a result, the first date at which the Company has applied IFRS
was January 1, 2014 (the Transition Date). IFRS 1
requires first-time adopters to retrospectively apply all effective IFRS
standards as of the reporting date, which for the Company
will be December 31, 2015. However, it also provides for certain optional
exemptions and certain mandatory exceptions for first-
time IFRS adoption. Prior to transition to IFRS, the Company prepared its

financial statement in accordance with Canadian

generally accepted accounting principles (pre-changeover Canadian GAAP).

29.1 Mandatory exceptions and optional elections

The IFRS 1 applicable exemptions and exceptions applied in the conversion from

pre-changeover Canadian GAAP to IFRS are

as follows:

Unaudited Unaudited

December 31 Decem ber 31 January 1

Debt to capital ratio 2015 2014 2014

$ $ $

Sum of long term debt and shareholder's equity

Long term debt 10,707 10,917 11,127

Shareholder's equity 12,636 12,993 11,686

23,343 23,910 22,813

Key Ratio - Debt to Capital

Ratio of debt to debt plus equity 0.46 0.46 0.49

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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29.1 Mandatory exceptions and optional elections (continued)

Derecognition of financial assets and liabilities

The Company has applied the derecognition requirements in IAS 39 prospectively
for transactions occurring on or after January
1, 2014. As a result any non-derivative financial assets or non-derivative
financial liabilities derecognized in accordance with pre-
changeover Canadian GAAP as a result of a transaction that occurred before
January 1, 2014, have not been recognized in
accordance with IFRS unless they qualify for recognition as a result of a
later transaction or event.

Estimates

The estimates previously made by the Company under pre-changeover Canadian
GAAP were not revised for the application of
IFRS, except where necessary to reflect any difference in accounting policy or
where there was objective evidence that those
estimates were in error. As a result, the Company has not used hindsight to
revise estimates.

Government loans

The Company classifies government loans received as financial liabilities or
equity instruments in accordance with IAS 32
Financial Instruments: Presentation. At the date of transition, these loans
are measured at the pre-changeover Canadian GAAP
carrying amount as a government grant. No benefit element is recognized for
below market interest rate loans. The loans are
subsequently measured using an effective interest rate calculated at the date
of transition and the guidance in IAS 20 Accounting
for Government Grants and Disclosure of Government Assistance is applied after
the date of transition.

Borrowing costs

The Company has elected to apply the optional election in the transitional

provisions of IAS 23 Borrowing Costs which permits
prospective capitalization of borrowing costs on qualifying assets from the
Transition Date.
Deemed cost for Operations subject to Rate Regulation
The Company has elected the deemed cost exemption applicable to entities
subject to rate regulation as described under IFRS 1.
The election permits the Company, at the date of transition to IFRS, to use
the previous Canadian GAAP carrying amount of
items of PP&E and intangible assets as deemed cost (thereby eliminating any
accumulated depreciation balances existing at the
date of transition); hence there will be no impact on retained earnings for
opening balances of PP&E and intangible assets at the
date of transition. In accordance with the election, the Company has tested
these items of property, plant and equipment and
intangible assets at the date of transition to IFRS. No impairment losses were
recognized.
Transfers of Assets from Customers
The Company has elected to apply the IFRS 1 election to only apply IFRIC 18
prospectively from the date of transition to non-
repayable supply contributions made by customers.
29.2 Reconciliations of pre-changeover Canadian GAAP to IFRS
IFRS 1 requires an entity to reconcile cash flows, equity, and comprehensive
income for prior periods as shown below.
In the statement of changes in cash flows, there is a reclassification from
the movement in regulatory assets and regulatory
liabilities to a movement in the regulatory deferral account balance. These
are both shown as movements within investing
activities and as such do not result in material adjustments to the net cash

flow balance.

The explanations for the impact of the transition to IFRS on the specific
accounts is described below. Reconciliation of equity and
comprehensive income as previously reported under Canadian GAAP to IFRS are
provided below. Other than employee post-
retirement benefits, sick pay benefits and the related deferred taxes, all
other items have no impact on Equity or Comprehensive
Income as they are reclassifications within the relevant statements.

Orillia Power Distribution Corporation
NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2015
(in thousands of Canadian dollars unless otherwise noted)

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29.2 Reconciliations of pre-changeover Canadian GAAP to IFRS (continued)
STATEMENT OF FINANCIAL POSITION
As at
(in thous ands of Canadian dollars)
$ $ $ $
ASSETS
Current Assets
Cas h and cas h equivalents 20 - - 20
Accounts receivable 3,524 - - 3,524
Unbilled energy and dis tribution revenue 3,985 - - 3,985
Paym ent in lieu of taxes receivable 3 55 - - 355

Inventories 6 18 - - 618

Prepaid expens es 1 66 - - 166

Future incom e tax as s et (a) 2 33 (233) - -

Due from related parties 8 27 - - 827

Current as s ets 9,728 (233) - 9,495

Non-current Assets

Property, plant and equipm ent 20,330 - - 20,330

Intangible as s ets 1 37 - - 137

Regulatory as s ets (b) 3 42 (342) - -

Deferred incom e tax as s et (a) (c) (d) 1,458 (80)

73 1,451

Non-current as s ets 22,267 (422) 73 21,918

Total assets 31,995 (655) 73 31,413

Regulatory deferral account debit balances (b) (c) (e) - 1,930 1,930

Total assets and regulatory deferral account debit balances 31,995 1,275 73

33,343

Notes

IFRS

January 1,

2014

Previous

GAAP Dec.

31, 2013

Am ounts

Reclas s ed

Im pact of

trans ition to

IFRS

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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29.2 Reconciliations of pre-changeover Canadian GAAP to IFRS (continued)

STATEMENT OF FINANCIAL POSITION

As at Notes

(in thous ands of Canadian dollars)

$ $ $ $

LIABILITIES AND SHAREHOLDER'S EQUITY

Current Liabilities

Bank indebtednes s 9 50 - - 950

Accounts payable and accrued liabilities (f) 5,681 - 41 5,722

Cus tom er s ecurity depos its 71 - - 71

Current portion of long term debt 2 10 - - 210

Current liabilities 6,912 - 41 6,953

Non-current Liabilities

Cus tom er s ecurity depos its 2 38 - - 238

Pos t-retirem ent benefits (g) 5 25 - 227 752

Regulatory liabilities (e) (h) 1,522 (1,522) - -

Long term debt 10,917 - - 10,917

Non-current liabilities 13,202 (1,522) 2 27 11,907

Shareholder's Equity

Share capital 8,236 - - 8,236

Contributed capital (i) 2,351 (2,351) - -

Retained earnings (i) 1,294 2,351 - 3,645

Accum ulated other com prehens ive los s (d) (f) (g) - - (195) (195)

Shareholder's equity 11,881 - (195) 11,686

Total liabilities and shareholder's equity 31,995 (1,522) 73 30,546

Regulatory deferral account credit balances (c) (h) - 2,797 - 2,797

Total equity, liabilities and regulatory deferral account credit balances

31,995 1,275 73 33,343

Previous

GAAP Dec.

31, 2013

Am ounts

Reclas s ed

T2 BAR CODE RETURN

Name: Orillia Power Distribution Corporation

BN: 86512 0596 RC 0001
Tax Year Start: 2015-01-01
Tax Year End: 2015-12-31

Im pact of

trans ition to

IFRS

IFRS

January 1,

2014

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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STATEMENT OF COMPREHENSIVE INCOME

Year ended Decem ber 31

(in thous ands of Canadian dollars)

$ $ $ $

Revenue

Recovered energy purchas es 33,821 - - 33,821

Operating revenue (j) (k) (l) (m 7,933 7 20 - 8,653

41,754 7 20 - 42,474

Expens es

Energy purchas es (n) 33,821 2 29 - 34,050

Operating expens es (o) (p) (q) 4,647 (33)

(16) 4,598

Depreciation and am ortization (m) 1,087 14 - 1,101

Los s on dis pos al of property plant and equipm ent (l) - 16 - 16

- 39,555 2 26 (16) 39,765

Operating profit 2,199 4 94 16 2,709

Finance incom e (r) 9 5 - 14

Finance cos ts (667) (29)

- (696)

Profit before paym ents in lieu of taxes 1,541 4 70 16 2,027

Provis ion for paym ent in lieu of taxes

Current provis ion 74 - - 74

Deferred provis ion (s) (t) (u) 2 62 (114) 37 185

3 36 (114) 37 259

Profit for the year before net m ovem ent in regulatory deferral account

balance 1,205 5 84 (21) 1,768

Net m ovem ent in regulatory deferral account balances (v) - (551) (551)

Profit for the year after net m ovem ent in regulatory deferral account

balances 1,205 33 (21) 1,217

Other comprehensive income:

Item s that will not be reclas s ified s ubs equently to profit and los s :

Actuarial gain on defined benefit plans net of deferred taxes (t) (w) - (33)

123 90

T2 BAR CODE RETURN

Name: **Orillia Power Distribution Corporation**

BN: 86512 0596 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

Total comprehensive income for the year 1,205 - 102 1,307

Am ounts

Reclas s ed

Im pact of

trans ition to

IFRS

2014 IFRS

2014

Previous

GAAP

Notes

Orillia Power Distribution Corporation

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2015

(in thousands of Canadian dollars unless otherwise noted)

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29.2 Reconciliations of pre-changeover Canadian GAAP to IFRS (continued)

END OF FINANCIAL STATEMENT

EXPLANATIONS OF AMOUNTS RECLASSIFIED AND IFRS TRANSITION IMPACTS

(a) Reclas s ification of current deferred taxes to non-current deferred tax as s ets $233

(b) Reclas s ification of regulatory as s ets $342 to regulatory deferral account debit balances

(c) Deferred incom e tax as s ets reduced by am ount of $313 reallocated to related regulatory balances

(d) Deferred tax im pact of pos t retirem ent benefits and s ick pay accrual on trans ition date com prehens ive incom e $73

(e) Debits included in regulatory liabilities reallocated to regulatory deferral account debits

(f) Es tim ated balance of trans ition date s ick leave benefit accrual of $41

(g) Es tim ated balance of trans ition date pos t retirem ent benefit accrual of $227 included in com prehes ive incom e

(h) Credits included in regulatory liabilities reallocated to regulatory deferral account credit balances

(i) Contributed capital included in equity s ince incorporation reallocated to retained earnings $2,351

(j) Regulatory debit from depreciation difference in us eful lives $646 reclas s ified to net m ovem ent in regulatory

(k) Other regulatory revenues and expens es $44 reclas s ified to net m ovem ent in regulatory

(l) Los s on dis pos al of PP&E $16 reclas s ified from other revenue

(m) Am ortization of deferred revenue $14 reclas s ified to depreciation and am ortization

(n) Variance between energy purchas ed and recovered $229 reallocated to net m ovem ent in regulatory

(o) Decreas e in pos t retirem ent benefits expens e of $19

(p) Increas e in s ick leave benefit accrual of $3

(q) Retailer cos t variances $4 reallocated to net m ovem ent in regulatory

(r) Interes t on deferral account balances $5 reallocated to net m ovem ent in regulatory

(s) Increas e in deferred tax provis ion re pos t retirem ent benefits $37

(t) Reallocation of deferred tax expens e related to actuarial gain on pos t retirem ent benefits $33

(u) Reallocation of deferred tax expens e re regulatory debits and credits $81

(v) Am ounts reallocated to net m ovem ent in regulatory $551=(n)-(j)-(k)-(q)-(r)-(u)

(w) Experience gain per actuarial valuation $123

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

Assets – lines 1000 to 2599

1000	601,839	1060	3,419,924	1120	500,828
1400	811,717	1480	4,152,520	1484	169,438
1599	9,656,266	1600	287,077	1601	14,383
1602	-2,444	1680	988,833	1681	-95,363
1774	193,704	1775	-80,767	1900	24,361,420
1901	-1,955,800	2008	25,845,417	2009	-2,134,374
2420	2,126,487	2421	1,079,000	2589	3,205,487
2599	36,572,796				

Liabilities – lines 2600 to 3499

2620	5,757,915	2680	216,596	2700	2,000,000
2920	210,000	3139	8,184,511	3210	735,000
3220	1,165,990	3260	9,762,000	3320	3,635,326
3328	453,330	3450	15,751,646	3499	23,936,157

Shareholder equity – lines 3500 to 3640

3500	8,235,883	3580	-105,000	3600	4,505,756
3620	12,636,639	3640	36,572,796		

Retained earnings – lines 3660 to 3849

3660	2,498,772	3680	873,321	3700	-1,230,000
3740	2,363,663	3849	4,505,756		

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	44,344,213	8089	44,344,213	8100	8,085
8210	-78,835	8230	78,000	8299	44,351,463

Cost of sales – lines 8300 to 8519

8320	36,292,097	8518	36,292,097	8519	8,052,116

Operating expenses – lines 8520 to 9369

8522	267,199	8523	25,192	8670	1,150,002
8710	37,284	8714	657,506	9060	1,834,004
9284	2,738,858	9367	6,710,045	9368	43,002,142
9369	1,349,321				

Extraordinary items and taxes – lines 9970 to 9999

9970	1,349,321	9990	322,000	9995	154,000
9999	873,321				

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

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
Orillia Power Distribution Corporation	86512 0596 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			873,321	A
Add:				
Provision for income taxes – current	101	322,000		
Provision for income taxes – deferred	102	154,000		
Amortization of tangible assets	104	1,150,002		
Loss on disposal of assets	111	78,835		
Charitable donations and gifts from Schedule 2	112	259,249		
Non-deductible meals and entertainment expenses	121	12,596		
Other reserves on lines 270 and 275 from Schedule 13	125	477,076		
Reserves from financial statements – balance at the end of the year	126	745,959		
Subtotal of additions		3,199,717 ▶	3,199,717	
Other additions:				
Miscellaneous other additions:				
600 Deferred debits C GAAP add back per TB	290	648,290		
603 Inducement - ITA 12(1)(x) 51,356; Total 51,356	293	51,356		
604 Total	294			
Subtotal of other additions	199	699,646 ▶	699,646	
Total (lines 101 to 199)	500	3,899,363 ▶	3,899,363	B
Amount A **plus** amount B			4,772,684	C
Deduct:				
Capital cost allowance from Schedule 8	403	1,765,951		
Cumulative eligible capital deduction from Schedule 10	405	1,365		
Other reserves on line 280 from Schedule 13	413	541,664		
Reserves from financial statements – balance at the beginning of the year	414	924,016		
Subtotal of deductions		3,232,996 ▶	3,232,996	
Other deductions:				
Miscellaneous other deductions:				
704 Total	394			
Subtotal of other deductions	499	▶		
Total (lines 401 to 499)	510	3,232,996 ▶	3,232,996	D
Net income (loss) for income tax purposes (amount C **minus** amount D)			1,539,688	E

Enter amount E on line 300 of the T2 return.

Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) of the ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Select this check box to add all the amounts to income calculated in Schedule 1. . . . . ☐

Ontario

A		
☐	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
X	Ontario co-operative education tax credit	3,000
X	Ontario apprenticeship training tax credit	48,356
☐	Ontario computer animation and special effects tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario film and television tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario interactive digital media tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario sound recording tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario book publishing tax credit	
X	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☐	Ontario business-research institute tax credit	
☐	Ontario community food program donation tax credit for farmers	

Tax credits whose amount should reduce the capital cost of property

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees;
  - the Ontario community food program donation tax credit for farmers;
  - the eligible amount of gifts to Canada, a province, or a territory;
  - the eligible amount of gifts of certified cultural property;
  - the eligible amount of gifts of certified ecologically sensitive land; or
  - the additional deduction for gifts of medicine.
- All legislative references are to the federal *Income Tax Act*, unless otherwise specified.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts are eligible for a 5-year carryforward except for gifts of certified ecologically sensitive land made after February 10, 2014, which are eligible for a 10-year carryforward.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the federal *Act*.
- Subsection 110.1(1.2) of the federal Act provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient		Amount ($100 or more only)
Various		257,999
Georgian College		1,250
	Subtotal	259,249
	Add: Total donations of less than $100 each	
	Total donations in current tax year	259,249

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year			A		
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year	240		B		
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1)	210	259,249		259,249	259,249
Subtotal (line 250 **plus** line 210)		259,249	C	259,249	259,249
Subtotal (amount B **plus** amount C)		259,249	D	259,249	259,249
Deduct: Adjustment for an acquisition of control	255				
Total charitable donations available (amount D **minus** amount on line 255)		259,249	E	259,249	259,249
Deduct: Amount applied in the current year against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return)	260	259,249		259,249	259,249
Charitable donations closing balance (amount E **minus** amount on line 260)	280				
Ontario community food program donation for farmers included in the amount on line 260 (for donations made after December 31, 2013)	262				
Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %)			1		

Enter the amount from line 1 on line 420 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less; the Ontario income tax otherwise payable or the amount on line 1. For more information, see section 103.1.2 of the *Taxation Act, 2007* (Ontario).

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
7th prior year	2008-12-31			
8th prior year	2007-12-31			
9th prior year	2006-12-31			
10th prior year	2005-12-31			
11th prior year	2004-12-31			
12th prior year	2003-12-31			
13th prior year	2002-12-31			
14th prior year	2001-12-31			
15th prior year	2000-12-31			
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %				1,154,766	F
Taxable capital gains arising in respect of gifts of capital property included in Part 1 **		225			G
Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01)		227			H
The amount of the recapture of capital cost allowance in respect of charitable donations	230				
Proceeds of disposition, **less** outlays and expenses**					I
Capital cost**					J
Amount I or J, whichever is less	235				
Amount on line 230 or 235, whichever is less					K
Subtotal (**add** amounts G, H, and K)					L
Amount L **multiplied** by 25 %					M
Subtotal (amount F **plus** amount M)				1,154,766	N
Maximum allowable deduction for charitable donations (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less)				259,249	O

* For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year				A
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339			
Gifts to Canada, a province, or a territory at the beginning of the current tax year	340			B
Add:				
Gifts to Canada, a province, or a territory transferred on an amalgamation or the wind-up of a subsidiary	350			
Total gifts made to Canada, a province, or a territory in the current year*	310			
Subtotal (line 350 **plus** line 310)				C
Subtotal (amount B **plus** amount C)				D
Deduct:				
Adjustment for an acquisition of control	355			
Amount applied in the current year against taxable income (enter this amount on line 312 of the T2 return)	360			
Subtotal (line 355 **plus** line 360)				E
Gifts to Canada, a province, or a territory closing balance (amount D **minus** amount E)	380			

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			F		
Deduct: Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year	440		G		
Add:					
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			H		
Subtotal (amount G **plus** amount H)			I		
Deduct:					
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			J		
Gifts of certified cultural property closing balance (amount I **minus** amount J)	480				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
7th prior year	2008-12-31			
8th prior year	2007-12-31			
9th prior year	2006-12-31			
10th prior year	2005-12-31			
11th prior year	2004-12-31			
12th prior year	2003-12-31			
13th prior year	2002-12-31			
14th prior year	2001-12-31			
15th prior year	2000-12-31			
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			K		
Deduct: Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year	540		L		
Add:					
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014 (include this amount on line 112 of Schedule 1)	510				
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014 (include this amount on line 112 of Schedule 1)	520				
Subtotal (**add** lines 550, 510, and 520)			M		
Subtotal (amount L **plus** amount M)			N		
Deduct:					
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			O		
Gifts of certified ecologically sensitive land closing balance (amount N **minus** amount O)	580				

* For the federal and Alberta, gifts made before February 11, 2014 , expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made during a tax year that ended after March 23, 2006 expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . .

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
7th prior year	2008-12-31			
8th prior year	2007-12-31			
9th prior year	2006-12-31			
10th prior year	2005-12-31			
11th prior year*	2004-12-31			
12th prior year	2003-12-31			
13th prior year	2002-12-31			
14th prior year	2001-12-31			
15th prior year	2000-12-31			
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to determine the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years.
For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Part 6 – Additional deduction for gifts of medicine

		Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year			P				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the current tax year	640		Q				
Add:							
Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

a ______ x (b / c) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

a ______ x (b / c) = Additional deduction for gifts of medicine for the current year ______

Alberta

a ______ x (b / c) = Additional deduction for gifts of medicine for the current year ______

where:

a is the **lesser** of line 2 and line 4

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

		Federal		Québec	Alberta
Subtotal (line 650 **plus** line 610)			R		
Subtotal (amount Q **plus** amount R)			S		
Deduct:					
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			T		
Additional deduction for gifts of medicine closing balance (amount S **minus** amount T)	680				

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2014-12-31	
2nd prior year	2013-12-31	
3rd prior year	2012-12-31	
4th prior year	2011-12-31	
5th prior year	2010-12-31	
6th prior year*	2009-12-31	
7th prior year	2008-12-31	
8th prior year	2007-12-31	
9th prior year	2006-12-31	
10th prior year	2005-12-31	
11th prior year	2004-12-31	
12th prior year	2003-12-31	
13th prior year	2002-12-31	
14th prior year	2001-12-31	
15th prior year	2000-12-31	
16th prior year		
17th prior year		
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total		

* These gifts expired in the current year.

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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
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

- 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 (Complete if payer corporation is connected)	C Business Number of connected corporation 210 (Complete if payer corporation is connected)	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 (Complete if payer corporation is connected)	E Non-taxable dividend under section 83 230
				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 (Complete if payer corporation is connected)	H Dividend refund of the connected payer corporation (for tax year in column D)** 260 (Complete if payer corporation is connected)	I Part IV tax before deductions F x rate *** 270	
							J

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: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

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	Business Number	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note)	Taxable dividends paid to connected corporations	Eligible dividends (included in column D)
	400	**410**	**420**	**430**	
1	Orillia Power Corporation	89197 8215 RC0001	2015-12-31	1,230,000	

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 1,230,000

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** 1,230,000

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) 1,230,000

Other dividends paid in the tax year (total of 510 to 540) . . . .

Total dividends paid in the tax year **500** 1,230,000

Deduct:

Dividends paid out of capital dividend account **510**

Capital gains dividends **520**

Dividends paid on shares described in subsection 129(1.2) **530**

Taxable dividends paid to a controlling corporation that was bankrupt
at any time in the year **540**

Subtotal ______ ►

Total taxable dividends paid in the tax year that qualify for a dividend refund 1,230,000

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

- 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 . . . . . . 1,539,688 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") 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) 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") . . . . . . 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** h

Subtotal (amount g **plus** amount h) ▶ I

Subtotal (amount H **plus** amount I) 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 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)					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		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)			▶		M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)				180	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	30,460	a		
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205		b		
Subtotal (amount a **plus** amount b)		30,460	▶	30,460	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)				30,460	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)				30,460	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)				30,460	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	30,460	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 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 (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*.

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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 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 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
1,280,439		1,280,439	147,250

Ontario basic income tax (from Schedule 500)	270	147,250		
Deduct: Ontario small business deduction (from Schedule 500)	402			
Subtotal		147,250	147,250	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)			147,250	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")			147,250	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")			147,250	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")			147,250	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)			147,250	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	9,000		
Ontario apprenticeship training tax credit (from Schedule 552)	454			
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		9,000	9,000	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		138,250	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	138,250

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 7

Aggregate Investment Income and Active Business Income

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

- This schedule is for the use of Canadian-controlled private corporations (CCPCs) to calculate:
  - for the purpose of determining the refundable portion of Part I tax, aggregate investment income and foreign investment income, as defined in subsection 129(4) of the *Income Tax Act;*
  - specified partnership income, when the CCPC is a member of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part I Tax" in Guide T4012, *T2 Corporation – Income Tax Guide.*

Part 1 – Aggregate investment income

The aggregate investment income is the aggregate **world** source income.

Eligible portion of taxable capital gains for the year				002		A
Deduct:						
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	012		a			
Net capital losses of previous years claimed on line 332 on the T2 return	022		b			
Subtotal (amount a **plus** amount b)			▶			B
Amount A **minus** amount B (if negative, enter "0")						C
Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada)	032	8,085	c			
Deduct:						
Exempt income	042		1			
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year	052		2			
Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses)	062		3			
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	072		4			
Subtotal (**add** amounts 1 to 4) ▶			d			
Subtotal (amount c **minus** amount d)		8,085	▶		8,085	D
Amount C **plus** amount D					8,085	E
Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)				082		F
Amount E **minus** amount F (if negative, enter "0")				092	8,085	G

Enter amount G on line 440 of the T2 return.

Part 2A – Canadian investment income calculation

Eligible portion of taxable capital gains for the year before taking into account the capital gains reserve (federal) of Schedule 13		1.1		
Reserve's eligible portion (addition/deduction)		1.2		
Taxable capital gains under section 34.2 of the ITA		1.3		
The eligible portion of taxable capital gains for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts 1.1, 1.2 and 1.3)		▶		1a
Deduct:				
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		2a		
Net capital losses of previous years of other years claimed on line 332 on the T2 return		3a		
Allowable capital losses under section 34.2 of the ITA		3.1		
Total of amounts 2a, 3a and 3.1		▶		4a
Amount 1a **minus** amount 4a (if negative, enter "0")				5a
Taxable dividends		6.1		
Rental property income (under regulation 1100(11))		6.2		
Other property income	8,085	6.3		
Property income under section 34.2 of the ITA (line 280 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)		6.4		
Total property income from **Canadian** sources	8,085	▶	8,085	6a
Deduct:				
Exempt income		7a		
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year		8a		
Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses)		9a		
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		10a		
Total of amounts 7a to 10a		▶		11a
Amount 6a **minus** amount 11a			8,085	12a
Amount 5a **plus** amount 12a			8,085	13a
Rental property losses (under regulation 1100(11))		14.1		
Dividend losses		14.2		
Other property losses		14.3		
Property losses under section 34.2 of the ITA (line 280 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)		14.4		
Total property losses from **Canadian** sources		▶		14a
Amount 13a **minus** amount 14a (if negative, enter "0")			8,085	15a

Part 2 – Foreign investment income

The foreign investment income is all income from sources **outside Canada**.

Eligible portion of taxable capital gains for the year before taking into account the capital gains reserve (federal) of Schedule 13			H1		
Reserve's eligible portion (addition/deduction)			H2		
Taxable capital gains under section 34.2 of the ITA*			H3		
Eligible portion of taxable capital gains for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts H1, H2 and H3)			►	**001**	H
Allowable capital losses for the year			I1		
Allowable capital losses under section 34.2 of the ITA*			I2		
Eligible portion of allowable capital losses for the year (including allowable business investment losses) (total of amounts I1 and I2)			►	**009**	I
Subtotal (amount H **minus** amount I) (if negative, enter "0")					J
Taxable dividends	e1				
Rental property income (under regulation 1100(11))	e2				
Other property income	e3				
Property income under section 34.2 of the ITA (line 280 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)*	e4				
Total income from property from a source **outside Canada** (net of related expenses)	►	**019**	e		
Deduct:					
Exempt income **029**	5				
Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses) **049**	6				
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) **059**	7				
Subtotal (**add** amounts 5 to 7)	►		f		
Subtotal (amount e **minus** amount f)			►		K
Amount J **plus** amount K					L
Rental property losses (under regulation 1100(11))			M1		
Dividend losses			M2		
Other property losses			M3		
Property losses under section 34.2 of the ITA (line 280 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)*			M4		
Total losses from property from a source **outside Canada**			►	**069**	M
Amount L **minus** amount M (if negative, enter "0")				**079**	N

(enter amount N on line 445 of the T2 return)

* When an amount is entered on these lines, the amounts calculated for the taxable capital gains or allowable capital losses on lines 1.3 and 3.1 as well as property income or losses on lines 6.4 and 14.3 in Part 2A, "Canadian investment income calculation" are automatically updated. For more details, press F1 to consult the Help.

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

	A		B
Is the corporation a designated member of the partnership?*	Partnership name **200**	Partnership's account number	Total income (loss) of partnership from an active business **300**
Yes No			

C	D1	D2	D3	D	E
Corporation's share of amount column B **310**	Adjustment under section 34.2**	Expenses incurred to earn partnership income	Income amount earned by the corporation for the year from the provision of services or property to the partnership*	Adjustments (column D1 **minus** column D2 **plus** column D3) **315**	Corporation's income (loss) of the partnership (column C **plus** column D) **320**

Total **350**

E1	E2	F	G	H	I
Amount assigned by a member of the partnership to the corporation that is a designated member of the partnership*	Specified partnership's business limit amount assigned by the corporation to a designated member of the partnership*	Number of days in the partnership's fiscal period **325**	Prorated business limit or assigned amount*** **330**	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0") **340**

Total **385** **360**

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . **370** ________ g

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) . . . . **380** ________ h

Subtotal (amount g **plus** amount h) ________ i

Amount at line 385 or amount i, whichever is less . . . . **390** ________ O

Specified partnership income (line 360 **plus** amount O) . . . . **400** ________ P

Enter amount P at line T in Part 4.

Part 3 – Specified partnership income (continued)

* As a result of the tabling of the Federal Budget on March 22, 2016, modifications have been made to the calculations of the specified partnership's income. For more information, consult the Help (F1).

** In general, amounts included under subsections 34.2(2), (3), and (12) or claimed under subsections 34.2(4) and (11) are deemed to have the **same character** and be in the **same proportions** as the partnership income they relate to. For example, if a corporation receives $100,000 of partnership income for the partnership's fiscal period ending in its tax year, and that income is made up of $40,000 of active business income, $30,000 of income from property, and $30,000 as a taxable capital gain, the corporation's adjusted stub period accrual (ASPA) in respect of the partnership would be 40% active business income, 30% property income, and 30% taxable capital gains. Add or deduct **only the portion** of the following amounts that is deemed under subsection 34.2(5) to be **active business income**:

Add:

- the ASPA under subsection 34.2(2) (column 4 of Schedule 73)
- the income inclusion for a new corporate member of a partnership under subsection 34.2(3) (column 6 of Schedule 73)
- the previous-year transitional reserve under subsection 34.2(12) (column 12 of Schedule 73)

Deduct:

- the previous-year ASPA under subsection 34.2(4) (column 5 of Schedule 73)
- the previous-year income inclusion for a new corporate member of a partnership under subsection 34.2(4) (column 7 of Schedule 73)
- the current-year transitional reserve under subsection 34.2(11) (column 11 of Schedule 73)

*** When the corporation is a member of the partnership, Column G is equal to the result of the following equation: (column C ÷ column B) x ($500,000 x (column F ÷ 365)) - column E2. If the total in column C is negative, enter “0.”

When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income for the purpose of calculating the prorated business limit in column G. Enter on line h the total of all loss from column E.

When the corporation is a designated member of the partnership, Column G is equal to the amount in column E1.

Part 4 – Partnership income not eligible for the small business deduction

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 in Part 3 (if the net amount is negative, enter "0" on line U) . . . . ______ Q

Specified partnership loss (from amount h in Part 3) . . . . ______ R

Subtotal (amount Q **plus** amount R) ______ S

Deduct:

Specified partnership income (from amount P in Part 3) . . . . ______ T

Partnership income not eligible for the small business deduction (amount S **minus** amount T) . . . . **450** ______ U
(enter on line p in Part 5)

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return		1,539,688	j			
Plus:						
Allowable business investment loss from line 406 of Schedule 1			k			
Subtotal (amount j **plus** amount k)		1,539,688	▶		1,539,688	V
Deduct:						
Foreign business income after deducting related expenses*	500		l			
Taxable capital gains from line 113 of Schedule 1			m			
Net property income (amount c** **minus** amounts 1, 2, and F* in Part 1)		8,085	n			
Personal services business income and other income after deducting related expenses*	520		o			
Specified corporate income not eligible for the small business deduction***			o.1			
Income deemed to be active business income under subsection 129(6) ITA from an associated corporation that is not a CCPC or that is a CCPC that elects to be a third corporation under subsection 256(2)ITA***			o.2			
Subtotal (**add** amounts l to o.2)		8,085	▶		8,085	W
Net amount (amount V **minus** amount W)					1,531,603	X
Deduct:						
Partnership income not eligible for the small business deduction (amount U in Part 4)			p			
Income allocated to the corporation under subsection 96(1.1)	530		q			
Subtotal (amount p **plus** amount q)			▶			Y
Income from active business carried on in Canada (amount X **minus** amount Y) (enter amount Z on line 400 of the T2 return - if negative, enter "0")					1,531,603	Z

* If negative, enter amount in brackets, and **add** instead of **subtracting**.

** Net of related expenses.

*** As a result of the tabling of the Federal Budget on March 22, 2016, modifications have been made to the calculations of the income from active business. For more information, consult the Help (F1).

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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.	3	Buildings	637,424			0		637,424	5	0	0	31,871	605,553
2.	1	Distribution System	12,444,550			0		12,444,550	4	0	0	497,782	11,946,768
3.	8	Office Furniture	186,007	12,839		0	6,420	192,426	20	0	0	38,485	160,361
4.	10		466,516	65,418		0	32,709	499,225	30	0	0	149,768	382,166
5.	12	Computer Software		33,410		0	16,705	16,705	100	0	0	16,705	16,705
6.	45	Computer	172			0		172	45	0	0	77	95
7.	46	Server Hardware	1,740			0		1,740	30	0	0	522	1,218
8.	47	Transmission and Distribution	11,442,879	1,822,625		0	911,313	12,354,191	8	0	0	988,335	12,277,169
9.	50	Computer Equipment	49,838	46,116		0	23,058	72,896	55	0	0	40,093	55,861
10.	1	Additions to Class 3 Buildings		115,630		0	57,815	57,815	4	0	0	2,313	113,317
		Totals	25,229,126	2,096,038			1,048,020	26,277,144				1,765,951	25,559,213

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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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		2,096,038		
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	+			
Other (specify):				
Contributions in aid of construction not on S8	+	134,720		
Construction in progress not on S8	+	64,510		
Total additions per books	=	2,295,268	▶	2,295,268
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):				
Back out book depreciation on land rights not an S8 asset	+	-1,179		
Adjust for "negative" tools and equip data entry error on U03	+			
Rounding	+	-6		
Total proceeds per books	=	-1,185	▶ –	-1,185
Depreciation and amortization per accounts – Schedule 1			–	1,150,002
Loss on disposal of fixed assets per accounts			–	78,835
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	1,067,616

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		23,412,027
Opening net book value	–	22,344,411
Net change per financial statements	=	1,067,616

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
Orillia Power Distribution Corporation	86512 0596 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.	Orillia Power Corporation		89197 8215 RC0001	1					
2.	Orillia Power Generation Corporatio		86512 2998 RC0001	3					
3.	Bawitik Power Corporation		82005 1050 RC0001	4					
4.	2345997 Ontario Inc.		84603 7133 RC0001	3					
5.	2346005 Ontario Inc.		84224 7447 RC0001	3					
6.	2429106 ONTARIO INC.		80088 9974 RC0001	3					
7.	2429108 Ontario Inc.		80088 9776 RC0001	3					
8.	2429111 Ontario Inc.		82005 1050 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
Orillia Power Distribution Corporation	86512 0596 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	13,131	A
Add: Cost of eligible capital property acquired during the taxation year	222	8,492			
Other adjustments	226				
Subtotal (line 222 plus line 226)		8,492 x 3 / 4 =	6,369		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")			6,369 ▶	6,369	D
Amount transferred on amalgamation or wind-up of subsidiary			224		E
Subtotal (add amounts A, D, and E)			230	19,500	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)				19,500	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	19,500				
less amount from line 249					
Current year deduction	19,500	x 7.00 % =	250	1,365 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			1,365 ▶	1,365	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	18,135	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
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

- 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	X	110 131,860	115		43,526	120 88,334
Reserve for undelivered goods and services not rendered	X	130 345,216	135	108,114		140 453,330
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		270 477,076	275	108,114	43,526	280 541,664

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	Employee Future Benefits	552,000		96,145		648,145
2	Regulatory Liabilities	-105,060			386,290	-491,350
3	Unvested Sick Pay			47,500		47,500
4						
	Reserves from Part 2 of Schedule 13	477,076		108,114	43,526	541,664
	Totals	924,016		251,759	429,816	745,959

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 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* 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 from the list below 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.

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 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 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	Orillia Power Distribution Corporation	86512 0596 RC0001	1	500,000			
2	Orillia Power Corporation	89197 8215 RC0001	1	500,000			
3	Orillia Power Generation Corporation	86512 2998 RC0001	1	500,000	100.0000	500,000	
4	2345997 Ontario Inc.	84603 7133 RC0001	1	500,000			
5	2346005 Ontario Inc.	84224 7447 RC0001	1	500,000			
6	2429106 ONTARIO INC.	80088 9974 RC0001	1	500,000			
7	2429108 Ontario Inc.	80088 9776 RC0001	1	500,000			
8	2429111 Ontario Inc.	82005 1050 RC0001	1	500,000			
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the Act

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. The amount at line 415 is determined using the formula 0.225% x (D - $10,000,000). Details of this formula and variable D are in subsection 125(5.1) of the Act.

* 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 for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year, whichever is less.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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		
Capital stock (or members' contributions if incorporated without share capital)	103	8,235,883	
Retained earnings	104	4,505,756	
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		
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)		12,741,639 ►	12,741,639 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)			12,741,639	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121			
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			
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)		▶		B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		12,741,639	

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	
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	

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)		12,741,639	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	12,741,639	

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)	12,741,639	x	Taxable income earned in Canada **610**	1,280,439	=	**Taxable capital employed in Canada** **690**	12,741,639
			Taxable income	1,280,439			

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 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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	Orillia Power Corporation	89197 8215 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
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

On: 2015-12-31

- 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.
- 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	5,449,761 A
Taxable income for the year (DICs enter "0") *		110	1,280,439 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	8,085			
Subtotal (**add** lines 120, 130, and 140)		8,085 ►	8,085 C		
Income taxable at the general corporate rate (amount B **minus** amount C) (if negative enter "0")		150	1,272,354		
After-tax income (line 150 **multiplied** by 0.72 (the general rate factor for the tax year))				190	916,095 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 (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)					6,365,856 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	6,365,856
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W in Part 2)				560	
GRIP at the end of the tax year (line 490 **minus** line 560)				590	6,365,856

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 2014-12-31

Taxable income before specified future tax consequences from the current tax year		600,807 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)	14,234 M1		
Subtotal (**add** amounts K1, L1, and M1)	14,234 ►	14,234 N1	
Subtotal (amount J1 **minus** amount N1) (if negative, enter "0")		586,573 ►	586,573 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year 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 546,305 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) 16,334 M2

Subtotal (**add** amounts K2, L2, and M2) 16,334 ▶ 16,334 N2

Subtotal (amount J2 **minus** amount N2) (if negative, enter "0") 529,971 ▶ 529,971 O2

Future tax consequences that occur for the current year 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 . . . 1,818,189 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) . . . 18,333 M3

Subtotal (**add** amounts K3, L3, and M3) 18,333 ▶ 18,333 N3

Subtotal (amount J3 **minus** amount N3) (if negative, enter "0") 1,799,856 ▶ 1,799,856 O3

Future tax consequences that occur for the current year 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
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

Do not use this area

- 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.

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		1,230,000			
Total taxable dividends paid in the tax year	100	1,230,000			
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	6,365,856	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
Orillia Power Distribution Corporation	86512 0596 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 * . . . . 1,280,439 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A from Part 1) . . . . 147,250 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)	1,531,603	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 = 365 / 365 = ______ 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 ** = 1,280,439.00 / 1,280,439 = ... 1.00000 E

Amount D × ODF (line E) ______ c

Ontario taxable income (amount B from Part 2) 1,280,439 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 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2015-12-31

- 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)
Orillia Power Distribution Corporation

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	2000-10-26	1446923

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
360	West Street South	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Orillia	ON	CA	L3V 6J9

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 Hurley (Last name) **451** Pat (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 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
Orillia Power Distribution Corporation	86512 0596 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
Pat Hurley	(705) 326-7315

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** 23,842

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 Name of university, college, or other eligible educational institution **400**	**B** Name of qualifying co-operative education program **405**
1.	Georgian College	Electrical Engineering Technology/Technician
2.	Georgian College	Electrical Engineering Technology/Technician
3.	Georgian College	Electrical Engineering Technology/Technician
4.		

	C Name of student **410**	**D** Start date of WP (see note 1 below) **430**	**E** End date of WP (see note 2 below) **435**
1.	Joseph Orleni	2015-09-08	2015-12-18
2.	Jacob Bozek	2015-04-05	2015-09-04
3.	Joseph Orleni	2015-01-05	2015-04-24
4.			

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.		15.000 %	10,352	30.000 %		14
2.		15.000 %	11,590	30.000 %		22
3.		15.000 %	10,352	30.000 %		16
4.		15.000 %		30.000 %		

	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.	3,106	3,000	3,000		3,000
2.	3,477	3,000	3,000		3,000
3.	3,106	3,000	3,000		3,000
4.					

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.

Ontario

Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL059

ORILLIA POWER DISTRIBUTION CORPORATION
ATTENTION: C/O DAREK GRASSE
360 WEST ST SOUTH
PO BOX 398 STN MAIN
ORILLIA ON L3V 6J9

Issue Date	19-Jul-2016
Business No.	865120596TW0001
Reference No.	L2082772288

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2015	Return As Filed
Total Federal Tax	$193,656.00
Total Ontario Tax	$147,250.00
Total Credits	($19,332.00)
Loss Carry-back	$0.00
Total Tax Payable	$321,574.00
Interest	$4,414.97
Current Penalty	$0.00
Credits/Payments	($325,574.00)
Total Assessment	**$414.97**

As of 19-Jul-2016, including the amount assessed above, you have an overall balance on your account of $414.97.

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

28/07/16

Enclosure

G/L 20-100-6045-00-0-000

Ministry use only

Enquiries	1 866 ONT-TAXS 1 866 668-8297	Fax 1 866 888-3850	Teletypewriter (TTY) 1 800 263-7776 Internet **ontario.ca/finance**